ANNUAL REPORT REGARDING
LONG RANGE NEEDS FOR EXPANSION OF ELECTRIC GENERATION FACILITIES FOR SERVICE IN NORTH CAROLINA

REQUIRED PURSUANT TO G.S. 62-110.1(c)

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THE GOVERNOR OF NORTH CAROLINA
AND
THE JOINT LEGISLATIVE COMMISSION ON GOVERNMENTAL OPERATIONS

SUBMITTED BY
THE NORTH CAROLINA UTILITIES COMMISSION

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New River Light and Power Company

Western Carolina University

North Carolina Electric Membership Corporation

ElectriCities of North Carolina

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ABBREVIATIONS AND ACRONYMS

Blue Ridge Blue Ridge EMC
BREDL Blue Ridge Environmental Defense League
CC combined-cycle
CECPCN Certificate of Environmental Compatibility and Public Convenience and Necessity
CEUS Central and Eastern United States
CIGFUR Carolina Industrial Group for Fair Utility Rates
COD commercial operation date
COL combined construction and operating license
CPCN Certificate of Public Convenience and Necessity
CT combustion turbine/s
CUCA Carolina Utility Customers Association, Inc.
DOE U.S. Department of Energy
DSM demand-side management
Duke Duke Energy Carolinas, LLC
EE energy efficiency
EMC electric membership corporation
EnergyUnited EnergyUnited EMC
EPAct 2005 Energy Policy Act of 2005
FERC Federal Energy Regulatory Commission
GEH GE-Hitachi Nuclear Energy Americas, LLC
GreenCo GreenCo Solutions, Inc.
GridSouth GridSouth Transco, LLC
G.S. General Statute
GWh gigawatt-hour/s
Halifax Halifax EMC
Haywood Haywood EMC
IOU investor-owned electric utility
IRP integrated resource planning/integrated resource plans
kWh kilowatt-hour/s
MAREC Mid-Atlantic Renewable Energy Coalition
MATS Mercury Air Toxics Standard
MW megawatt/s
MWh megawatt-hour/s
NC Power Dominion North Carolina Power
NC-RETS North Carolina Renewable Energy Tracking System
NCEMC North Carolina Electric Membership Corporation

ABBREVIATIONS AND ACRONYMS (continued)

NCEMPA North Carolina Eastern Municipal Power Agency
NCMPA1 North Carolina Municipal Power Agency No. 1
NCSEA North Carolina Sustainable Energy Association
NCTPC North Carolina Transmission Planning Collaborative
NC WARN North Carolina Waste Awareness and Reduction Network
NERC North American Electric Reliability Corporation
NRC Nuclear Regulatory Commission
OASIS Open Access Same-time Information System
OATT open access transmission tariff
ODEC Old Dominion Electric Cooperative
OPSI Organization of PJM States, Inc.
Piedmont Piedmont EMC
PJM PJM Interconnection, LLC
Progress Duke Energy Progress, Inc.
PSCSC Public Service Commission of South Carolina
PURPA Public Utility Regulatory Policies Act of 1978
PV photovoltaic
REC renewable energy certificate/s
REPS Renewable Energy and Energy Efficiency Portfolio Standard
RFP request for proposals
ROE return on equity
RTO regional transmission organization
Rutherford Rutherford EMC
SACE Southern Alliance for Clean Energy
Santee Cooper Public Service Authority of South Carolina
SCC State Corporation Commission of Virginia
SCE&G South Carolina Electric & Gas
Senate Bill 3 Session Law 2007-397
SEPA Southeastern Power Administration
SERC Southeastern Electric Reliability Corporation
TOU time-of-use
TVA Tennessee Valley Authority
VEPCO Virginia Electric and Power Company
WPSA Wholesale Power Supply Agreement

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APPENDICES

1. EXECUTIVE SUMMARY

This annual report to the Governor and the General Assembly is submitted pursuant to General Statute (G.S.) 62-110.1(c), which specifies that each year the North Carolina Utilities Commission shall submit to the Governor and appropriate committees of the General Assembly a report of its analysis of the long-range needs for the expansion of facilities for the generation of electricity in North Carolina and a report on its plan for meeting those needs. Much of the information contained in this report is based on reports to the Commission by the electric utilities regarding their analyses and plans for meeting the demand for electricity in their respective service areas. It also reflects information from other records and files of the Commission.

There are three regulated investor-owned electric utilities (IOUs) operating under the laws of the State of North Carolina and subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, Inc. (Progress), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (Duke), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion North Carolina Power (NC Power).

Duke and Progress, the two largest electric IOUs in North Carolina, together supply about 96% of the utility-generated electricity consumed in the state. Approximately 18% of the IOUs' 2012 electric sales in North Carolina were to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

Table ES-1 shows the gigawatt-hour (GWh) sales of the regulated electric utilities in North Carolina.

Table ES-1: Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2012	2011	2012	2011	2012	2011
Progress	36,589	37,353	15,298	12,360	58,390	56,223
Duke	54,709	55,405	4,519	5,213	81,362	82,127
NC Power	4,115	4,177	1,101	914	80,942	82,325

*GWh = 1 Million kWh (kilowatt hours)

During the 2013 to 2027 timeframe, the average annual growth rate in summer peak demand for electricity in North Carolina is forecasted to be in the range of 0.9% to 1.7%. Table ES-2 illustrates the systemwide average annual growth rates forecast by the IOUs that operate in North Carolina. Each uses generally accepted forecasting methods and, although their forecasting models are different, the econometric techniques employed by each are widely used for projecting future trends. Under normal weather patterns, summer peak demand remains higher than winter peak demand for all three IOUs.

Table ES-2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2013 – 2027)

	Summer Peak	Winter Peak	Energy Sales
Progress	0.9%	1.2%	1.0%
Duke	1.7%	1.7%	1.7%
NC Power	1.5%	1.5%	1.6%

North Carolina's IOUs depend on coal-fired and nuclear-fueled steam generation to produce the overwhelming majority of their electric output, as illustrated in Table ES-3. It should be noted that the purchased power listed in the table includes buyback transactions associated with jointly owned coal and nuclear plants.

Table ES-3: Total Energy Resources by Fuel Type for 2012

	Progress	Duke	NC Power
Coal	34%	33%	21%
Nuclear	38%	49%	33%
Net Hydroelectric*	1%	1%	0%
Oil and Natural Gas	18%	6%	18%
Wood/Biomass	0%	0%	1%
Purchased Power	9%	11%	27%

* See discussion of pumped storage in Section 6.

On August 20, 2007, with the signing of Session Law 2007-397 (Senate Bill 3), North Carolina became the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under this new law, investor-owned utilities in North Carolina will be required to meet up to 12.5% of their energy needs through renewable energy resources or energy efficiency measures by 2021. Rural electric cooperatives and municipal electric suppliers are subject to a 10% REPS requirement. In general, electric power suppliers may comply with the REPS requirement in a number of ways, including the use of renewable fuels in existing electric generating facilities, the generation of power at new renewable energy facilities, the purchase of power from renewable energy facilities, the purchase of renewable energy certificates (RECs), or the implementation of energy efficiency measures. This issue is discussed further in Section 8.

A map showing the service areas of the North Carolina IOUs can be found at the back of this report.

2. INTRODUCTION

The General Statutes of North Carolina require that the Utilities Commission analyze the probable growth in the use of electricity and the long-range need for future generating capacity in North Carolina. The General Statutes also require the Commission to submit an annual report to the Governor and to the General Assembly regarding future electricity needs. G.S. 62-110.1(c) provides, in part, as follows:

> The Commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion of facilities for the generation of electricity in North Carolina, including its estimate of the probable future growth of the use of electricity, the probable needed generating reserves, the extent, size, mix and general location of generating plants and arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission and other arrangements with other utilities and energy suppliers to achieve maximum efficiencies for the benefit of the people of North Carolina, and shall consider such analysis in acting upon any petition by any utility for construction . . . Each year, the Commission shall submit to the Governor and to the appropriate committees of the General Assembly a report of its analysis and plan, the progress to date in carrying out such plan, and the program of the Commission for the ensuing year in connection with such plan.

Some of the information necessary to conduct the analysis of the long-range need for future electric generating capacity required by G.S. 62-110.1(c) is filed by each regulated utility as a part of the Least Cost Integrated Resource Planning process. Commission Rule R8-60 defines an overall framework within which least cost integrated resource planning takes place. Commonly called integrated resource planning (IRP), it is a process that takes into account conservation, energy efficiency, load management, and other demand-side options along with new utility-owned generating plants, non-utility generation, renewable energy, and other supply-side options in order to identify the resource plan that will be most cost-effective for ratepayers consistent with the provision of adequate, reliable service.

Prior to July 1, 2013, Commission Rule R8-60(b) specified that the IRP process was applicable to the North Carolina Electric Membership Corporation (NCEMC) and any individual electric membership corporation (EMC) to the extent that it is responsible for procurement of any or all of its individual power supply resources. However, with the ratification of Session Law 2013-187 on June 26, 2013, EMCs have been exempted from filing IRPs with the Commission, effective July 1, 2013.

This report is an update of the Commission's November 7, 2012 Annual Report. It is based primarily on reports to the Commission by the regulated electric utilities serving North Carolina, but also includes information from other records and Commission files. Much of the material was gathered in Docket No. E-100, Sub 137, 2012 Biennial Integrated Resource Plans and Related 2012 REPS Compliance Plans.

3. OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY IN NORTH CAROLINA

There are three regulated investor-owned electric utilities (IOUs) operating in North Carolina subject to the jurisdiction of the Commission. All three of the IOUs own generating facilities. They are Duke Energy Progress, Inc. (Progress), whose corporate office is in Raleigh; Duke Energy Carolinas, LLC (Duke), whose corporate office is in Charlotte; and Virginia Electric and Power Company (VEPCO), whose corporate office is in Richmond, Virginia, and which does business in North Carolina under the name Dominion North Carolina Power (NC Power). A map outlining the areas served by the IOUs can be found at the back of this report.

Duke and Progress, the two largest IOUs, together supply about 96% of the utility generated electricity consumed in the state. As of December 31, 2012, Duke had 1,865,000 customers located in North Carolina, and Progress had 1,290,000. Each also has customers in South Carolina. NC Power supplies approximately 4% of the state's utility generated electricity. It has 119,000 customers in North Carolina. The large majority of its corporate operations are in Virginia, where it does business under the name of Virginia Electric and Power Company. About 18% of the IOUs' North Carolina electric sales are to the wholesale market, consisting primarily of electric membership corporations and municipally-owned electric systems.

Based on annual reports submitted to the Commission for the 2012 reporting period, the gigawatt-hour (GWh) sales for the electric utilities in North Carolina are summarized in Table 1.

Table 1: Electricity Sales of Regulated Utilities in North Carolina

	NC Retail GWh*		NC Wholesale GWh*		Total GWh Sales* (NC Plus Other States)	
	2012	2011	2012	2011	2012	2011
Progress	36,589	37,353	15,298	12,360	58,390	56,223
Duke	54,709	55,405	4,519	5,213	81,362	82,127
NC Power	4,115	4,177	1,101	914	80,942	82,325

*GWh = 1 Million kWh (kilowatt hours)

The Commission does not regulate the retail rates of municipally-owned electric systems or electric membership corporations. However, the Commission does have jurisdiction over the licensing of all new electric generating plants and large scale transmission facilities built in North Carolina.

EMCs are independent, non-profit corporations. There are 31 EMCs serving 1,044,000 customers in North Carolina, including 26 that are headquartered in the state. The other five are headquartered in adjacent states. These EMCs serve customers in 95 of the state's 100 counties. Twenty-five of the EMCs are members of NCEMC, an umbrella service organization. NCEMC is a generation and transmission services cooperative that provides wholesale power and other services to its 25 members.

Six EMCs operating in the state are not members of NCEMC. As noted above, five are incorporated in contiguous states and provide service in limited areas across the border into North Carolina. The sixth is French Broad EMC.

Since 1980, NCEMC has been a part owner in the baseload Catawba Nuclear Station located in York County, South Carolina. Duke operates and maintains the station, which has been operational since 1985. NCEMC's ownership share consists of 61.51% of Unit 1, approximately 700 megawatts (MW) and 30.754% in the common support facilities of the station. NCEMC's ownership entitlement is guaranteed through a reliability exchange between the Catawba Nuclear Station and Duke's McGuire Nuclear Station located in Mecklenburg County. Additionally, Duke may purchase surplus energy generated from NCEMC's portion of the Catawba Nuclear Station. As an alternative, this surplus may be sold on a wholesale basis to a third party.

NCEMC owns and operates about 680 MW of combustion turbine (CT) generation at sites in Anson and Richmond County. These peaking resources operate on natural gas as primary fuel, with diesel storage on-site as a secondary fuel. On August 25, 2010, NCEMC received a Certificate of Public Convenience and Necessity (CPCN) for a sixth generating unit (56 MW) at the Richmond County/Hamlet CT Plant. This new generating unit came online in July 2013. This addition results in a total Hamlet CT Plant output of 339 MW.

NCEMC also owns and operates two diesel-powered generating stations on the Outer Banks of North Carolina (located on Ocracoke Island and in Buxton). These peaking units, which began commercial operation in 1991, have a combined capacity of 18 MW and are used primarily for peak shaving and voltage support. Also, most EMCs receive an allocation of hydroelectric power from the Southeastern Power Administration (SEPA)**.**

Exercising their right to cease full participation in NCEMC's power supply program, five members of NCEMC gave notice that they will be responsible for their future power supply resources. NCEMC refers to these EMCs as Independent Members. Blue Ridge EMC (Blue Ridge), EnergyUnited EMC (EnergyUnited), Piedmont EMC (Piedmont), Rutherford EMC (Rutherford), and Haywood EMC (Haywood) are Independent Members.

Under a Wholesale Power Supply Agreement (WPSA), NCEMC is obligated to supply Independent Members with electric power and energy from existing contract and generation resources. To the extent that the electric power and energy supplied under the WPSA is not sufficient to meet the electric energy requirements of its customers, the Independent Members must independently arrange for purchases of additional electric power from a third party, or parties.

The service territories of NCEMC's member EMCs are located within the control areas of Progress, Duke, and NC Power. Therefore, NCEMC's system consists of three distinct areas known as supply areas. Historically, NCEMC planned for each of these supply areas separately, primarily serving load with all requirements purchased power contracts with the control area power supplier, plus its ownership share of the Catawba Nuclear Station. Renegotiation of certain power supply contracts and the introduction of new resources into NCEMC's power supply portfolio have provided the flexibility to serve load in multiple supply areas using the same resource. To the extent that firm transmission access is obtained and maintained, NCEMC continues to serve all its members as a single integrated system. NCEMC currently purchases wholesale electricity from Progress, Duke, Dominion, American Electric Power, South Carolina Electric & Gas (SCE&G), Southern Power and SEPA.

NCEMC and Progress executed a Tolling Agreement whereby NCEMC will toll the output of NCEMC's Anson facility to Progress from January 1, 2013 through December 31, 2032. Under this agreement, NCEMC owns and maintains the Anson facility for the exclusive use of meeting the joint needs of NCEMC and Progress. Progress will purchase, schedule, and deliver natural gas and diesel fuel to meet these dispatch requirements. In addition, NCEMC and Southern Power have a baseload sale agreement. Under this agreement NCEMC has agreed to sell 100 MW to Southern Power. This sale started on January 1, 2012 and ends on December 31, 2021.

In addition to the EMCs, there are about 75 municipal and university owned electric distribution systems serving approximately 572,000 customers in North Carolina. Most of these systems are members of ElectriCities, an umbrella service organization. ElectriCities is a non-profit organization that provides many of the technical, administrative, and management services needed by its municipally-owned electric utility members in North Carolina, South Carolina, and Virginia.

New River Light and Power, located in Boone, and Western Carolina University, located in Cullowhee, are both university-owned members of ElectriCities. Unlike other members of ElectriCities, the rates charged to customers by these two small distribution companies require Commission approval.

ElectriCities is a service organization for its members, not a power supplier. Fifty-one of the North Carolina municipals are participants in one of two municipal power agencies which provide wholesale power to their membership. ElectriCities' largest activity is the management of these two power agencies. The remaining members buy their own power at wholesale.

One agency, the North Carolina Eastern Municipal Power Agency (NCEMPA), is the wholesale supplier to 32 cities and towns in eastern North Carolina. NCEMPA owns portions of five Progress generating units (about 700 MW of coal and nuclear capacity). NCEMPA also has Supplemental Load Agreements with Progress that run through 2017. These contracts provide for additional power when load requirements exceed the capacity NCEMPA owns.

The other power agency is North Carolina Municipal Power Agency No. 1 (NCMPA1), which is the wholesale supplier to 19 cities and towns in the western portion of the state. NCMPA1 has a 75% ownership interest (832 MW) in Catawba Nuclear Unit 2, which is operated by Duke. It also has an exchange agreement with Duke that gives NCMPA1 access to power from the McGuire Nuclear Station and Catawba Unit 1.

NCMPA1 purchases power through bilateral agreements with other generators to obtain its requirements above its Catawba entitlement. To meet its supplemental power requirements, NCMPA1 has purchase power agreements with Duke, Southern Power, and SEPA. NCMPA1 also owns 65 MW of diesel-fueled distributed generation located at certain city delivery points, and has contracts for an additional 90 MW of generation owned by municipalities and retail customers which is available during times of high demand and spiking wholesale prices. NCMPA1 also owns two gas turbine generators located in Monroe that provide an additional 24 MW of peaking and reserve capacity.

The Tennessee Valley Authority (TVA), which generates electricity from coal, nuclear, and hydroelectric plants, sells energy directly to the Murphy, North Carolina, Power Board, and to three out-of-state cooperatives that supply power to portions of North Carolina: Blue Ridge Mountain EMC, Tri-State EMC, and Mountain Electric Cooperative. These distributors of TVA power are located in six North Carolina counties and serve over 33,000 households and 8,200 commercial and industrial customers. The North Carolina counties served by distributors of TVA power are Avery, Burke, Cherokee, Clay, McDowell, and Watauga.

TVA owns and operates four hydroelectric dams in North Carolina with a combined generation capacity of 523 MW. The dams are Apalachia and Hiwassee in Cherokee County, Chatuge in Clay County, and Fontana in Swain and Graham counties. TVA owns and/or maintains 10 substations and switchyards and nearly 119 miles of transmission line in North Carolina.

4. THE HISTORY OF INTEGRATED RESOURCE PLANNING IN NORTH CAROLINA

Integrated resource planning is an overall planning strategy which examines conservation, energy efficiency, load management, and other demand-side measures in addition to utility-owned generating plants, non-utility generation, renewable energy, and other supply-side resources in order to determine the least cost way of providing electric service. The primary purpose of integrated resource planning is to integrate both demand-side and supply-side resource planning into one comprehensive procedure that weighs the costs and benefits of all reasonably available options in order to identify those options which are most cost-effective for ratepayers consistent with the obligation to provide adequate, reliable service.

Initial IRP Rules

By Commission Order dated December 8, 1988, in Docket No. E-100, Sub 54, Commission Rules R8-56 through R8-61 were adopted to define the framework within which integrated resource planning takes place. Those rules incorporated the analysis of probable electric load growth with the development of a long-range plan for ensuring the availability of adequate electric generating capacity in North Carolina as required by G.S. 62-110.1(c).

The initial IRPs were filed with the Commission in April 1989. In May of 1990, the Commission issued an Order in which it found that the initial IRPs of Progress, Duke, and NC Power were reasonable for purposes of that proceeding and that NCEMC should be required to participate in all future IRP proceedings. By an Order issued in December 1992, Rule R8-62 was added. It covers the construction of electric transmission lines.

The Commission subsequently conducted a second and third full analysis and investigation of utility IRP matters, resulting in the issuance of Orders Adopting Least Cost Integrated Resource Plans on June 29, 1993, and February 20, 1996. A subsequent round of comments included general endorsement of a proposal that the two/three year IRP filing cycle, plus annual updates and short-term action plans, be replaced by a single annual filing. There was also general support for a shorter planning horizon than the fifteen years required at that time.

Streamlined IRP Rules (1998)

In April 1998, the Commission issued an Order in which it repealed Rules R8-56 through R8-59 and revised Rules R8-60 through R8-62. The new rules shortened the reported planning horizon from 15 to 10 years and streamlined the IRP review process while retaining the requirement that each utility file an annual plan in sufficient detail to allow the Commission to continue to meet its statutory responsibilities under G.S. 62-110.1(c) and G.S. 62-2(a)(3a).

These revised rules allowed the Public Staff and any other intervenor to file a report, evaluation, or comments concerning any utility's annual report within 90 days after the utility filing. The new rules further allowed for the filing of reply comments 14 days after any initial comments had been filed and required that one or more public hearings be held. An evidentiary hearing to address issues raised by the Public Staff or other intervenors could be scheduled at the discretion of the Commission.

In September 1998, the first IRP filings were made under the revised rules. The Commission concluded, as a part of its Order ruling on these filings, that the reserve margins forecast by Progress, Duke, and NC Power indicated a much greater reliance upon off-system purchases and interconnections with neighboring systems to meet unforeseen contingencies than had been the case in the past. The Commission stated that it would closely monitor this issue in future IRP reviews.

In June 2000, the Commission stated in response to the IOUs' 1999 IRP filings that it did not believe that it was appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at that time. The Commission concluded that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. The Commission did, however, want the record to clearly indicate its belief that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it would be actively monitoring the adequacy of existing electric utility reserve margins, and that it would take appropriate action in the event that any reliability problems developed.

Further orders required that IRP filings include a discussion of the adequacy of the respective utility's transmission system and information concerning levelized costs for various conventional, demonstrated, and emerging generation technologies.

Order Revising Integrated Resource Planning Rules – July 11, 2007

A Commission Order issued on October 19, 2006, in Docket No. E-100, Sub 111, opened a rulemaking proceeding to consider revisions to the IRP process as provided for in Commission Rule R8-60. On May 24, 2007, the Public Staff filed a Motion for Adoption of Proposed Revised Integrated Resource Planning Rules setting forth a proposed Rule R8-60 as agreed to by the various parties in that docket. The Public Staff asserted that the proposed rule addressed many of the concerns about the IRP process that were raised in the 2005 IRP proceeding and balanced the interests of the utilities, the environmental intervenors, the industrial intervenors, and the ratepayers. Without detailing all of the changes recommended in its filing, the Public Staff noted that the proposed rule expressly required the utilities to assess on an ongoing basis both the potential benefits of reasonably available supply-side energy resource options, as well as programs to promote demand-side management. The proposed rule also substantially increased both the level of detail and the amount of information required from the utilities regarding those assessments. Additionally, the proposed rule extended the planning horizon from 10 to 15 years, so the need for additional generation would be identified sooner. The information required by the proposed rule would also indicate the projected effects of demand response and energy efficiency programs and activities on forecasted annual energy and peak loads for the 15-year period. The Public Staff also noted that the proposed rule provided for a biennial, as opposed to annual or triennial, filing of IRP reports with an annual update of forecasts, revisions, and amendments to the biennial report. The Public Staff further noted that adoption of the proposed Rule R8-60 would necessitate revisions to Rule R8-61(b) to reflect the change in the frequency of the filing of the IRP reports.

With the addition of certain other provisions and understandings, the Commission ordered that revised Rules R8-60 and R8-61(b), attached to its Order as Appendix A, should become effective as of the date of its Order, which was entered on July 11, 2007. However, since the utilities might not have been able to comply with the new requirements set out in revised Rule R8-60 in their 2007 IRP filings, revised Rule R8-60 was ordered to be applied for the first time to the 2008 IRP proceedings in Docket No. E-100, Sub 118. These new rules were further refined in Docket No. E-100, Sub 113 to address the implementation of Senate Bill 3 requirements.

2012 Biennial IRP Proceeding
(Docket No. E-100, Sub 137)

2012 Biennial IRPs were filed by the following IOUs: Progress, Duke, NC Power, and the following EMCs: NCEMC, Rutherford, Piedmont, Haywood, and EnergyUnited. In addition, REPS compliance plans were submitted by the IOUs, GreenCo Solutions, Inc. (Greenco),[1] Halifax EMC (Halifax), and EnergyUnited.

The following parties intervened in this docket: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

Public Hearings were held in Raleigh on February 11, 2013, and in Charlotte on February 28, 2013. The Commission's October 14, 2013 Order approving the 2012 Biennial IRPs and related REPS compliance plans, which includes the procedural history, can be found in the back of this report as Appendix 1.

5. LOAD FORECASTS AND PEAK DEMAND

Forecasting electric load growth into the future is, at best, an imprecise undertaking. Virtually all forecasting tools commonly used today assume that certain historical trends or relationships will continue into the future and that historical correlations give meaningful clues to future usage patterns. As a result, any shift in such correlations or relationships can introduce significant error into the forecast. Progress, Duke, and NC Power each utilize generally accepted forecasting methods. Although their respective

[1] GreenCo filed consolidated REPS compliance plans on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

forecasting models are different, the econometric techniques employed by each utility are widely used for projecting future trends. Each of the models requires analysis of large amounts of data, the selection of a broad range of demographic and economic variables, and the use of advanced statistical techniques.

With the inception of integrated resource planning, North Carolina's electric utilities have attempted to enhance forecasting accuracy by performing limited end-use forecasts. While this approach also relies on historical information, it focuses on information relating to specific electrical usage and consumption patterns in addition to general economic relationships.

Table 2 illustrates the systemwide average annual growth rates in energy sales and peak loads anticipated by Progress, Duke, and NC Power. These growth rates are based on the utilities' system peak load requirements. Detailed load projections for the respective utilities are shown in Appendices 2, 3, and 4. Under normal weather patterns, the annual summer peak demand remains higher than the winter peak demand for the three IOUs serving North Carolina.

Table 2: Forecast Annual Growth Rates for Progress, Duke, and NC Power (After Energy Efficiency (EE) and Demand-Side Management (DSM) are Included) (2013 – 2027)

	Summer Peak	Winter Peak	Energy Sales
Progress	0.9%	1.2%	1.0%
Duke	1.7%	1.7%	1.7%
NC Power	1.5%	1.5%	1.6%

North Carolina utility forecasts of future peak demand growth rates are in the range of forecasts for the nation as a whole. The 2013-2022 Long-Term Reliability Assessment by the North American Electric Reliability Corporation (NERC) indicates that the national forecast of average annual growth in summer peak demand for that period is 1.35%.

Table 3 provides historical peak load information for Progress, Duke, and NC Power.

Table 3: Summer and Winter Systemwide Peak Loads for Progress, Duke, and NC Power Since 2008 (in MW)

	Progress		Duke		NC Power	
	Summer	Winter*	Summer	Winter*	Summer	Winter*
2008	12,290	11,832	18,228	16,968	19,051	17,904
2009	11,796	12,531	17,397	17,282	18,137	17,612
2010	12,074	12,230	17,358	17,570	19,140	17,689
2011	12,094	11,338	17,651	16,002	20,061	16,881
2012	12,770	12,376	17,610	15,307	19,249	17,623

Winter peak following summer peak

6. GENERATION RESOURCES

Traditionally, the regulated electric utilities operating in North Carolina have met most of their customer demand by installing their own generating capacity. These generating plants are usually classified by fuel type (nuclear, coal, gas/oil, hydro, etc.) and placed into three categories based on operational characteristics:

(1) Baseload – operates nearly full cycle;
(2) Intermediate (also referred to as load following) – cycles with load increases and decreases; and
(3) Peaking – operates infrequently to meet system peak demand.

Nuclear and large coal facilities, as well as combined-cycle natural gas units, serve as baseload plants and typically operate more than 5,000 hours annually. Smaller and older coal and oil/gas plants are used as intermediate load plants and typically operate between 1,000 and 5,000 hours per year. Finally, CTs and other peaking plants usually operate less than 1,000 hours per year.

All of the nuclear generation units operated by the utilities serving North Carolina have been relicensed so as to extend their operational lives. Duke has three nuclear facilities with a combined total of seven individual units. The McGuire Nuclear Station located near Huntersville is the only one located in North Carolina and it has two generating units. The other Duke nuclear facilities are located in South Carolina. All of Duke's nuclear units have been granted extensions of their original operating licenses by the Nuclear Regulatory Commission (NRC). The new license expiration dates fall between 2033 and 2043.

Progress has four nuclear units divided among three locations. Two of the locations are in North Carolina. The Brunswick facility, near Southport, has two units and the Harris Plant, near New Hill, has one unit. The Robinson facility, which also has one unit, is located in South Carolina. The NRC has renewed the operating licenses for all of Progress's nuclear units. The new renewal dates run from 2030 to 2046.

NC Power operates two nuclear power stations with two units each. Both stations are located in Virginia. All four units have been issued license extensions by the NRC. The new license expiration dates range from 2032 to 2040.

Hydroelectric generation facilities are of two basic types: conventional and pumped storage. With a conventional hydroelectric facility, which may be either an impoundment or run-of-river facility, flowing water is directed through a turbine to generate electricity. An impoundment facility uses a dam to create a barrier across a waterway to raise the level of the water and control the water flow; a run-of-river facility simply diverts a portion of a river's flow without the use of a dam.

Pumped storage is similar to a conventional impoundment facility and is used by Duke and NC Power for the large-scale storage of electricity. Excess electricity produced at times of low demand is used to pump water from a lower elevation reservoir into a higher elevation reservoir. When demand is high, this water is released and used to operate hydroelectric generators that produce supplemental electricity. Pumped storage produces only two-thirds to three-fourths of the electricity used to pump the water up to the higher reservoir, but it costs less than an equivalent amount of additional generating capacity. This overall loss of energy is also the reason why the total "net" hydroelectric generation reported by a utility with pumped storage can be significantly less than that utility's actual percentage of hydroelectric generating capacity.

Some of the electricity produced in North Carolina comes from non-utility generation. In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which established a national policy of encouraging the efficient use of renewable fuel sources and cogeneration (production of electricity as well as another useful energy byproduct – generally steam – from a given fuel source). North Carolina electric utilities regularly utilize non-utility, PURPA-qualified, purchased power as a supply resource.

An additional source of renewable generation comes from a program called NC GreenPower, which is a voluntary effort that uses financial contributions from North Carolina citizens and businesses to help offset the cost of producing "green energy." This program is discussed in Section 8 of this report.

Another type of non-utility generation is power generated by merchant plants. A merchant plant is an electric generating facility that sells energy on the open market. It is often constructed without a native load obligation, a firm long-term contract, or any other assurance that it will have a market for its power. These generating plants are generally sited in areas where the owners see a future need for an electric generating facility, often near a natural gas pipeline, and are owned by developers willing to assume the economic risk associated with the facility's construction.

The current capacity mix generated by each IOU is shown in Table 4.

Table 4: Installed Utility-Owned Generating Capacity by Fuel Type (Summer Ratings) for 2012

	Progress	Duke	NC Power
Coal	38%	34%	30%
Nuclear	27%	33%	19%
Hydroelectric	2%	15%	12%
Oil and Natural Gas	33%	18%	38%
Wood/Biomass	0%	0%	1%

The actual generation usage mix, based on the megawatt-hours (MWh) generated by each utility, reflects the operation of the capacity shown above, plus non-utility purchases, and the operating efficiencies achieved by attempting to operate each source of power as close to the optimum economic level as possible.

Generally, actual plant use is determined by the application of economic dispatch principles, meaning that the start-up, shutdown, and level of operation of individual generating units is tied to the incremental cost incurred to serve specific loads in order to attain the most cost effective production of electricity. The actual generation produced and power purchased for each utility, based on monthly fuel reports filed with the Commission for 2012, is provided in Table 5.

Table 5: Total Energy Resources by Fuel Type for 2012

	Progress	Duke	NC Power
Coal	34%	33%	21%
Nuclear	38%	49%	33%
Net Hydroelectric*	1%	1%	0%
Oil and Natural Gas	18%	6%	18%
Wood/Biomass	0%	0%	1%
Purchased Power	9%	11%	27%

* See the paragraph on pumped storage in this section.

The purchased power amounts shown above include buyback transactions associated with jointly owned coal and nuclear plants.

The Commission recognizes the need for a mix of baseload, intermediate, and peaking facilities and believes that conservation, energy efficiency, peak-load management, and renewable energy resources must all play a significant role in meeting the capacity and energy needs of each utility.

Progress Generation

As of September 2013, Progress had 12,902 MW of installed generating capacity (summer rating), including about 700 MW jointly-owned with NCEMPA. This does not include purchases and non-utility owned capacity.

Since 2010, Progress has retired 9 coal units, totaling more than 1,000 MW, in addition to 160 MW of older oil units. In December 2013, the last of Progress's coal units that lack advanced emission controls are scheduled to be retired. Sutton Steam Station Coal Units 1-3, located in Wilmington, NC, are currently planned for retirement, bringing the Company's total to approximately 1,600 MW of coal retirements. Following the retirement of these units, the Sutton Combined Cycle (CC) unit is also expected to be operational by the end of 2013.

In December 2012, the Lee CC unit at the Wayne County Energy Complex became operational. This 625 MW natural gas-fired CC generating station is located in Goldsboro, NC.

The 2013 Progress IRP identifies a need for new natural gas units. The following natural gas resources are included in the plan for the 2013 through 2028 planning horizon:

- 2013 – December 2013, 625 MW Sutton CC is scheduled to come online
- 2017 – December 2017, construct 126 MW of fast start combustion turbines (CTs)
- 2019 – Procure or construct 843 MW of natural gas CC generation
- 2021 – Procure or construct 843 MW of natural gas CC generation
- 2022 – Procure or construct 843 MW of natural gas CC generation
- 2027 – Procure or construct 403 MW of simple cycle CTs

Although the Company has suspended its NRC application for two proposed new nuclear units at its existing Harris site near New Hill in Wake County, it still believes that nuclear generation is important for the long-term benefits of its customers. The Company's 2013 IRP continues to support new nuclear generation as a carbon-free, cost-effective option within the Company's resource portfolio.

- V.C. Summer Nuclear Plant, Fairfield County, SC – Discussions continue with Santee Cooper to possibly purchase an interest in two units (4.1% share of two 1,100 MW units) under construction at the V.C. Summer Nuclear Plant in the 2018 through 2020 timeframe.

- W.S. Lee Nuclear Station, Cherokee, SC – While not in its Base Case, the Company shows an ownership interest in Duke's Lee Nuclear Station under its Joint Planning Scenario. Currently a new and updated site-specific seismic analysis is being conducted at the request of the NRC. Completion of this report delays licensing and pushes the project completion date to 2024.

Duke Generation

As of September 2013, Duke had 21,473 MW of installed generating capacity (summer rating), excluding purchases and non-utility owned capacity. That total includes generation jointly-owned with NCMPA1, NCEMC, and Piedmont Municipal Power Agency produced at Duke's Catawba Nuclear Facility in South Carolina.

Since 2011, Duke has retired 15 coal units, totaling 1,300 MW, in addition to 400 MW of older oil units. In April 2015, the last of Duke's coal stations that lack advanced emission controls is scheduled to be retired. Lee Steam Station Coal Units 1 and 2 (100 MW each), located in Pelzer, SC are currently planned for retirement to correspond with the effective date of the federal Mercury Air Toxics Standard (MATS), while Unit 3 (170 MW) is scheduled to be repowered to run on natural gas, also in 2015.

In December 2012, following the retirement of the Dan River coal units, the Dan River CC facility became operational. This 620 MW natural gas-fired generating station is located in Eden, NC. The 825 MW Cliffside Steam Station Coal Unit 6 located in Mooresboro, NC, also began commercial operation in December 2012.

On October 24, 2013, Duke filed an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN) with the Public Service Commission of South Carolina (PSCSC) seeking approval to construct and operate a 750 MW CC plant at the existing Lee Steam Station in Anderson County, SC. This filing was in partnership with NCEMC, which will be a minority owner of 100 MW of the project if constructed.

Though no final decision to build at Lee has been made, Duke believes it is prudent to continue with the regulatory actions necessary to keep the project moving forward. Construction could begin after the company receives the necessary regulatory approvals. The new plant could begin commercial operation as early as June 2017.

The 2013 Duke IRP identifies a need for new natural gas units. The following natural gas resources are included in the plan for the 2014 through 2028 planning horizon:

- 2015 – Convert a 170 MW coal unit to natural gas at the Lee Steam Station in SC
- 2017 – Construct a new 680 MW natural gas CC generation facility
- 2019 – Procure or construct 843 MW of natural gas CC generation
- 2022 – Procure or construct 403 MW of simple cycle CTs

Duke continues to explore the potential for a joint ownership share of the SCE&G V.C. Summer nuclear station. The 2013 plan shows a 5.9% share of the two 1,100 units being available for the summer peaks of 2018 and 2020, respectively. While shown to be cost-effective from a planning perspective, the acquisition of this capacity is still subject to successful completion of discussions as well as multiple regulatory approvals.

The Company submitted an application for a Combined Construction and Operating License (COL) and an environmental report to the NRC for the W.S. Lee Nuclear Station, in Cherokee, SC, on December 12, 2007. A supplement to the environmental report was filed September 24, 2009. The NRC issued its Draft Environmental Impact Statement for the Lee Nuclear plant in December 2011, concluding that the NCUC's evaluation of Duke's future load demand and its accuracy in historical load forecasting within the 2011 IRP was a reasonable basis for planning.

In April 2012, the NRC staff subsequently requested Duke to update the Lee Nuclear site-specific seismic analysis to incorporate the new Central and Eastern United States (CEUS) Seismic Source Characterization model (published as NUREG-2115 in January 2012). This negatively impacts the schedule for NRC issuance of the Lee COL. Completion of the new site-specific seismic analysis will delay the Lee COL issuance until the second quarter of 2016. Accordingly, Duke has moved the Commercial Operation Date (COD) for Lee Nuclear Unit 1 to 2024.

The Company continues to evaluate the optimal time to file the CECPCN for Lee Nuclear in South Carolina, as well as pursue other relevant regulatory approvals.

The Company will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level. Duke will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

NC Power / VEPCO Generation

As of September 2013, NC Power had 17,705 MW of existing Company owned generating capacity (summer rating). This excludes purchases and non-utility capacity. Of this total, only 480 MW is located in North Carolina.

The Company completed the conversion of Altavista (51 MW) on July 12, 2013, and will also complete the conversion of its Hopewell (51 MW) and Southampton (51 MW) units from coal to biomass fuel in 2013.

To meet expected load growth, the Company filed for a CPCN with the State Corporation Commission of Virginia (SCC) to construct and operate the Warren County Power Station, a 1,337 MW CC facility located in Warren County, Virginia. On February 27, 2012, the Company officially began construction of the station. The station will generate enough electricity for more than 300,000 homes at peak demand, which is critical to the Company's strategy to meet the growing need for electricity. The station is targeted for commercial operation by 2015.

The Company filed a CPCN with the SCC to repower its coal-fired Bremo Power Station with natural gas on August 31, 2012. The Bremo Power Station currently has two units, Unit 3 and Unit 4, which have been in service since 1950 and 1958, respectively.

Unit 3 has a summer capacity of 71 MW and Unit 4 has a summer capacity of 156 MW. This conversion is expected to reduce the Company's emissions of SO_2 NO_x, particulate matter, CO_2, and mercury. The conversion is expected to be complete in 2014.

On November 2, 2012, the Company filed an application for a CPCN with the SCC to construct and operate Brunswick County Power Station, a 1,375 MW natural gas powered electric generation facility located in Brunswick County, Virginia. On August 2, 2013, the SCC issued an order granting the CPCN. The Company forecasts a COD of 2016.

The Company is in the process of developing a new nuclear unit, North Anna 3 (1,453 MW), at its existing North Anna Power Station located in Louisa County in central Virginia, subject to receiving all required approvals.[2] The 2013 Plan has North Anna 3 achieving commercial operation in October 2024, with capacity being available to meet the summer peak in 2025. This is the earliest possible in-service date given permitting and construction lead times. The Company has not committed to build North Anna 3 to date but continues to develop the project to assure that this supply-side resource option remains available to its customers.

The Company has revised its technology selection for North Anna 3 to GE-Hitachi Nuclear Energy Americas LLC's (GEH) economic simplified boiling water reactor nuclear technology rather than the Mitsubishi Heavy Industries Advanced Pressurized Water Reactor identified in the 2012 Plan. This decision was based on a continuation of the competitive procurement process that began in 2009 to find the best solution to meet its need for future baseload generation. Since 2009, GEH has continued to refine its design and has made significant progress toward obtaining federal approval. In addition, GEH and its consortium partner Fluor Enterprises, Inc. provided contract enhancements that are expected to benefit customers and stakeholders over the new unit's planned 60-year life. In July 2013, the Company submitted a revised COL application to the NRC to reflect the change in technology.

The Company expects to receive the COL no earlier than late 2015 and intends to maintain the development option of North Anna 3 for several key reasons. Those reasons are as follows:

a. North Anna 3 will provide much needed baseload capacity to the region in the latter portion of the Planning Period while enhancing system reliability;
b. nuclear units are near emission-free generation;
c. North Anna 3 will enhance fuel diversity within the Company's generation portfolio, which will in turn, promote fuel price stability for customers; and
d. nuclear power is the lowest cost large-scale dispatchable baseload generating alternative to natural gas.

[2] Originally, Old Dominion Electric Cooperative (ODEC), part owner of North Anna Units 1 and 2, was also a participant in the development of North Anna 3 but informed the Company of its intent to no longer participate in February 2011. On January 30, 2013, the NRC approved the transfer of ODEC's interest to the Company.

Based on effective and anticipated environmental regulations, along with current market conditions, the 2013 Plan includes 1,097 MW of generating unit retirements through 2017. Several units will be retired by 2015. These units include the Chesapeake Energy Center Units 1 (111 MW), 2 (111 MW), 3 (156 MW), and 4 (217 MW) and Yorktown Units 1 (159 MW) and 2 (164 MW).

7. RELIABILITY AND RESERVE MARGINS

An electric system's reliability is its ability to continuously supply all of the demands of its consumers with a minimum interruption of service. It is also the ability of an electric system to withstand sudden disturbances, such as short circuits or sudden loss of system components due to scheduled or unscheduled outages. The reliability of an electric system is a function of the number, size, fuel type, and age of the utility's power plants; the different types and numbers of interconnections the utility has with neighboring electric utilities; and the environment to which its distribution and transmission systems are exposed.

There are several measurements of reliability utilized in the electric utility industry. Generally, they are divided between probabilistic measures (loss of load probability and the frequency and duration of outages) and non-probabilistic measures (reserve margin and capacity margin). One of the most widely used measures is the reserve margin.

The reserve margin is the ratio of reserve capacity to actual needed capacity (*i.e.*, peak load). It provides an indicator of the ability of an electric utility system to continue to operate despite the loss of a large block of capacity (generating unit outage and/or loss of a transmission line), deratings of generating units in operation, or actual load exceeding forecast load. A similar indicator is capacity margin, which is the ratio of reserve capacity to total overall capacity (i.e., reserve capacity plus actual needed capacity). Although reserve margin was the exclusive industry standard term for many years, capacity margin has also been widely used in recent years. This report continues to utilize reserve margin terminology.

It is difficult, if not impossible, to plan for major generating capacity additions in such a manner that constant reserve margins are maintained. Reserve margins will generally be lower just prior to placing new generating units into service and greater just after new generating units come online.

In earlier years, a 20% reserve margin was considered appropriate for long-range planning purposes. In recent years, the Commission has approved IRPs containing reserve margins lower than 20%. Adequate reliability can be preserved despite these lower reserve margins because of the increased availability of emergency power supplies from the interconnection of electric power systems across the country, the increasing efficiency with which existing generating units have been operated, and the relative size of utility generating units compared to overall load.

Forecasted yearly reserve margins for Progress, Duke, and NC Power are shown in Appendices 2, 3, and 4. The summer reserve margins currently projected by each IOU are shown in Table 6.

Table 6: Projected Summer Reserve Margins for Progress, Duke, and NC Power (2013-2027, after DSM)

	Reserve Margins
Progress	15.0% – 18.0%
Duke	15.0% – 22.7%
NC Power	5.8% – 16.4%

While coal and nuclear continue to remain the most widely used fuels in our area, most of the generation facilities constructed in recent years use natural gas as their primary fuel. With relatively low fuel costs and short construction lead times, natural gas generating units are efficient and produce relatively low emissions. Fuel deliverability, however, is a concern because of the nature of the infrastructure that delivers natural gas to the generating stations. Some regions of North America are served only by a few, or even a single, pipeline system. North Carolina, in fact, is almost entirely dependent on Transco Gas Pipeline for its natural gas requirements.

8. RENEWABLE ENERGY AND ENERGY EFFICIENCY

Renewable Energy and Energy Efficiency Portfolio Standard (REPS)

On August 20, 2007, with the signing of Senate Bill 3, North Carolina became the first state in the Southeast to adopt a REPS. Under this law, investor-owned electric utilities are required to increase their use of renewable energy resources and/or energy efficiency such that those sources meet 12.5% of their needs in 2021. EMCs and municipal electric suppliers are subject to a 10% REPS requirement. The requirements under the law phase in over time. In 2010, electric power suppliers were required to ensure that 0.02% of their retail electric sales in North Carolina come from solar energy resources. Additional requirements are effective in 2012 and subsequent years.

On October 1, 2013, the Commission submitted its fifth annual report to the Governor, the Environmental Review Commission, and the Joint Legislative Commission on Governmental Operations regarding Commission implementation of, and electric power supplier compliance with, the REPS. On the same date, the Commission also filed its third biennial report to the same entities regarding cost allocations as required by Senate Bill 3. That report discusses allocations of utility costs for renewable energy, demand-side management/energy efficiency, and fuel and fuel related charges. Both reports are available on the Commission's web site, www.ncuc.net.

Senate Bill 3 requires the Commission to monitor compliance with REPS and to develop procedures for tracking and accounting for renewable energy certificates (RECs). In 2008 the Commission opened Docket No. E-100, Sub 121 and established a stakeholder process to propose requirements for a North Carolina Renewable Energy Tracking System (NC-RETS). On October 19, 2009, the Commission issued a request for proposals (RFP) via which it selected a vendor, APX, Inc., to design, build, and operate the tracking system. NC-RETS began operating July 1, 2010, consistent with the requirements of Session Law 2009-475.

Members of the public can access the NC-RETS web site at www.ncrets.org. The site's "resources" tab provides information regarding REPS activities and NC-RETS account holders. NC-RETS also provides an electronic bulletin board where RECs can be offered for purchase.

As of November 15, 2013, NC-RETS had issued 14,887,901 renewable energy certificates and 2,797,698 energy efficiency certificates. In addition, 6,115,895 renewable energy certificates had been imported into NC-RETS accounts. (These certificates were issued by registries located outside of North Carolina.) About 320 organizations, including electric power suppliers and owners of renewable energy facilities, have established accounts in NC-RETS. About 603 renewable energy facilities participate as "projects" in NC-RETS, which means that NC-RETS issues renewable energy certificates to the facility owners based on the facilities' energy output.

REPS Compliance

For 2010 and 2011, each electric power supplier was subject to a .02% of retail sales REPS obligation. At the end of 2010 and 2011, each electric power supplier was required to have placed solar RECs that they acquired to meet their 2010 and 2011 REPS solar set-aside obligation into a compliance account within NC-RETS. When the Commission concluded its review of each electric power supplier's REPS compliance report, the associated RECs were permanently retired.

Starting in 2012, North Carolina's electric power suppliers were subject to an increased solar obligation of .07% of retail sales. In addition, starting in 2012 they were subject to: 1) a general REPS obligation of 3% of retail sales; 2) a swine waste resource obligation of .07% of retail sales, and 3) their pro-rata share of a 170,000 megawatt-hour statewide aggregated poultry waste resource obligation.

On May 16, 2012, the Commission issued an Order requiring all electric power suppliers to submit updates regarding their plans for meeting the 2012 swine and poultry waste REPS obligation. That Order stated that the REPS compliance plans that had been filed in 2011, and the Public Staff's comments regarding those plans, called into question whether the electric power suppliers would meet their 2012 swine and poultry waste resource obligations. Subsequently, the electric power suppliers requested that their 2012 and 2013 swine and poultry waste obligations be delayed by two years. The Commission held an evidentiary hearing in the matter on

August 28 and 29, 2012. On November 29, 2012, the Commission issued an Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief. In that Order the Commission eliminated the 2012 requirement for swine waste resources and delayed for one year the requirement for poultry waste resources.

On September 16, 2013, Duke, Progress, NC Power, GreenCo, the Public Works Commission of the City of Fayetteville, EnergyUnited, Halifax, and TVA filed a joint motion to modify and delay the 2013 poultry waste and swine waste set-aside requirements. On September 20, 2013, NCEMPA and NCMPA1 filed a joint motion requesting the same relief. On November 5, 2013, the Commission held an evidentiary hearing in this matter, which remains pending at this time.

Energy Efficiency

Electric power suppliers in North Carolina are required to implement demand-side management (DSM) and energy efficiency (EE) measures and use supply-side resources to establish the least cost mix of demand reduction and generation measures that meet the electricity needs of their customers. Energy reductions through the implementation of DSM and EE measures may also be used by the electric power suppliers to comply with REPS. Duke, Progress, NC Power, EnergyUnited, Halifax, and GreenCo have filed for and received approval for EE and DSM programs.

On August 30, 2013, the Commission filed its third biennial report to the Governor and the Joint Legislative Commission on Governmental Operations regarding proceedings for electric utilities involving EE and DSM cost recovery and incentives. That report lists the DSM and EE programs that have been reviewed by the Commission, and is available on the Commission's web site.

NC GreenPower

Formed in 2003, NC GreenPower is a statewide, nonprofit organization, the first in the nation of its kind, working to help improve the quality of the environment in North Carolina. NC GreenPower accepts voluntary contributions from residents and businesses that donate directly or through their utility bills to support local renewable energy and carbon offset projects. NC GreenPower partners with nearly all electric utilities across the state. They help by marketing the program to their customers and collecting donations for NC GreenPower through utility bills. All of the money is then simply passed over to NC GreenPower. Renewable energy funds are used to pay approved generators across the state for each kWh of green energy they produce and put onto the electric grid from their project. Carbon offset contributions are used to pay carbon mitigation projects, like landfill and animal waste methane capture, for every pound of greenhouse gas that is mitigated from their project. Funds support local projects and help create North Carolina jobs.

As of November 2013, NC GreenPower had agreements with 618 renewable energy generators, including 602 small solar photovoltaic (PV), 12 large solar PV, one small wind facility, and three landfill methane facilities.

June 2013 reporting to the NC GreenPower Board of Directors showed a total of 10,721 North Carolina electric consumers were donating to the program through their utility bills. Since the launch of the program, NC GreenPower renewable energy projects have generated 443 billion kWh of green power, and donors have helped provide nearly $5.5 million in incentive payments to the owners of about 900 renewable energy projects in almost every county across the State. Carbon offset projects have mitigated 10,300 tons of greenhouse gases – equivalent to the emissions from driving 29 million miles.

9. TRANSMISSION AND GENERATION INTERCONNECTION ISSUES

Transmission Planning

The North Carolina Transmission Planning Collaborative (NCTPC) was established in 2005. Participants (transmission-owning utilities, such as Duke and Progress, and transmission-dependent utilities, such as municipal electric systems and EMCs) identify the electric transmission projects that are needed to be built for reliability and estimate the costs of those upgrades. The NCTPC's January 2013 report stated that 11 major transmission projects are needed in North Carolina by the end of 2022 at an estimated cost of $318 million.

The NCTPC's report also provided the results of transmission studies regarding various hypothetical future scenarios: 1) three different scenarios for the wind generation located off the North Carolina and Virginia coasts, and 2) the impact of 500 MW of new generation located near Duke's existing Buck plant in Davidson County. The complete report is available at http://www.nctpc.net/nctpc/document/REF/2013-02-01/2012-2022_NCTPC_Report_FINAL_011713.pdf.

In addition to their work within the NCTPC, Duke and Progress are part of an inter-regional transmission planning initiative called the Southeast Interregional Participation Process. This effort allows a transmission customer, such as a municipal utility, to request a study of the transmission that would be required to be built to facilitate a hypothetical request to transport electric power across multiple regional planning areas. Other participating utilities include Alabama Electric Cooperative, Santee Cooper, Dalton Utilities, SCE&G, South Mississippi Electric Power Association, Entergy, Georgia Transmission Corporation, the Southern Companies, Municipal Electric Authority of Georgia, TVA, and E.ON U.S.

On February 16, 2007, the Federal Energy Regulatory Commission (FERC) issued Order No. 890, adopting changes to the pro-forma open access transmission tariff (OATT) to be used by transmission owners, including a new requirement for transmission providers to participate in a coordinated, open, and transparent planning process on both a local and regional level. The FERC required each transmission provider to file the details of its planning process, which had to satisfy nine planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. Duke and Progress both referred to the North Carolina Transmission Planning Collaborative as their mechanism and forum for assuring open transparent planning with opportunity for involvement by stakeholders. In order to address the FERC's requirements relative to inter-regional coordination, Duke and Progress cited their participation in the Southeast Interregional Participation Process.

In 2010, FERC opened a rulemaking regarding how to allocate the costs of large transmission projects in order to encourage development of renewable energy. The Commission and the Public Staff intervened in the proceeding, representing North Carolina electricity consumers. On July 21, 2011, the FERC issued a final rule entitled "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," also known as "Order 1000."[3] The Utilities Commission and the Public Staff jointly filed a request for rehearing, arguing that the rule infringes on state jurisdiction by mandating regional and inter-regional transmission planning processes and cost allocation methods. North Carolina's rehearing request is pending before FERC. In addition, numerous court challenges are pending before the DC Circuit Court of Appeals.

On May 21, 2012, the Commission issued an Order Scheduling Public Meeting and Requesting Comments on one issue raised by the FERC's Order No. 1000. Specifically, the Commission sought information relative to the legal and policy implications of Order No. 1000's requirement that public utility electric transmission service providers amend their federal OATTs to establish criteria and procedures for considering regional transmission projects[4] that would be sponsored, built and owned by non-incumbent transmission owners.[5] FERC's Order No. 1000 required that transmission operators file such tariff amendments by October 11, 2012.[6] North Carolina's three public utility transmission owners, specifically Duke, Progress, and NC Power are subject to Order No. 1000 (although NC Power's compliance will be via its regional transmission operator, PJM Interconnection, Inc. (PJM)).

On October 11, 2012, the Commission issued a report to the Governor and the General Assembly regarding this issue.[7] The Commission's report found that North

[3] FERC issued Order No. 1000 on July 21, 2011, in its Docket No. RM10-23-000.
[4] A regional transmission project is one that benefits two or more transmission owners and generally spans or connects two or more companies' electric transmission systems.
[5] FERC's Order No. 1000 defines a non-incumbent transmission developer as an entity that does not have a retail electric distribution service territory as well as a public utility that proposes transmission projects outside of its existing retail service territory.
[6] The filing by Duke and Progress was made on October 11, 2012, and is pending before the FERC in Docket No. ER13-83.
[7] The report is filed in Docket No. E-100, Sub 132.

Carolina law did not appear to preclude construction and ownership of electric transmission facilities by a non-incumbent transmission owner.

The Commission's investigation found that electric transmission ownership by non-incumbent transmission developers presented the following risks for the State's electricity consumers:

(1) The risk that electric customers would pay more for a transmission line than they would otherwise pay if the line were owned by Duke or Progress because the return on equity (ROE) for the project would be set by the FERC, and the FERC has been granting relatively high ROEs in order to reward transmission construction. Under the filed-rate doctrine,[8] the Commission would be required to honor FERC's ROE decision and allow retail electric utilities to pass on to their retail customers the non-incumbent transmission developer's transmission charges.

(2) The risk that a non-incumbent transmission developer would abandon its transmission project, either mid-way in the construction process, or many years later when the developer had recouped its investment and no longer has any incentive to maintain the project. Because such a developer would not be a traditional, franchised electric utility, it would have no on-going "obligation to serve."

(3) The risk that a non-incumbent developer would build a transmission project in a substandard or inherently unreliable manner, or fail to maintain the line over time, thus threatening service reliability. All transmission developers are subject to federal reliability standards. However, a non-incumbent transmission owner would not be subject to G.S. 62-42, which gives the Commission the authority to compel a public utility to upgrade its facilities if necessary to provide reliable service, or the Commission's Rules R8-40 and 41, which establish public utility requirements for addressing bulk electric system emergencies.

(4) The risk that, during a widespread grid outage or system emergency, system restoration or defensive operations would be delayed while Duke, Progress or NC Power coordinated restoration or operations decisions with the non-incumbent transmission owner.

(5) The risk that FERC's Order No. 1000 compliance orders for Duke, Progress and PJM would encourage non-incumbent transmission development, and thereby increase the occurrence of the risks outlined above.

The Commission recommended that the Governor and the General Assembly pursue statutory changes that would either:

[8] The "filed rate doctrine" holds that once the FERC sets rates to be charged interstate wholesale electric customers, a state may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. In other words, rates established by the FERC must be given binding effect by state utility commissions.

(a) preclude transmission construction and ownership by non-incumbent transmission owners; or

(b) give the Commission additional jurisdiction to regulate the service quality and emergency operations of non-incumbent transmission owners.

On July 3, 2013, Session Law 2013-232 was enacted. This law states that only a public utility may obtain a certificate to build a new transmission line (except a line for the sole purpose of interconnecting an electric power plant). In this context, a public utility includes investor-owned utilities, EMCs, joint municipal power agencies and cities and counties that operate electric utilities.

On October 11, 2012, Duke and Progress jointly submitted an Order No. 1000 compliance filing to FERC, in Docket No. ER13-83. That submission included proposed revisions to the utilities' OATTs that would (1) allow for third party ownership of regional transmission projects (as discussed above), (2) provide for the express consideration of "public policies" in the transmission planning process, and (3) provide that the costs of regional transmission projects would be allocated between the two companies based on the avoided cost of local transmission projects. On February 21, 2013, FERC issued an order in which it rejected the Duke/Progress compliance filing, ruling that the Companies' combined footprint could no longer be considered a "region." The FERC reasoned that due to the merger of Duke Energy Corp. and Progress Energy, Inc. the two utilities are no longer separate transmission providers. As such, FERC found that the NC Transmission Planning Collaborative is no longer a viable transmission planning region (although the NCTPC could still be operated as a "local" transmission planning process). FERC required Duke and Progress to file a further compliance filing via which they would be part of a compliant transmission planning region.

On May 22, 2013, Duke and Progress filed, under protest, a proposal to comply with Order No. 1000 by participating in the Southeastern Regional Transmission Planning[9] process. The Duke/Progress submittal noted that its request for rehearing of FERC's February 21, 2013, order was still pending. At this time, both the re-hearing petition and the May 22, 2013 compliance filing remain pending at FERC.

State Generator Interconnection Standards

On June 4, 2004, in Docket No. E-100, Sub 101, Progress, Duke, and NC Power jointly filed a proposed model small generator interconnection standard, application, and agreement to be applicable in North Carolina. In 2005, the Commission approved small generator interconnection standards for North Carolina.

In Session Law 2007-397, the General Assembly, among other things, directed the Commission to "[e]stablish standards for interconnection of renewable energy facilities and other nonutility-owned generation with a generation capacity of

[9] For more information about the Southeastern Interregional Transmission Planning process, see http://southeasternrtp.com/.

10 megawatts or less to an electric public utility's distribution system; provided, however, that the Commission shall adopt, if appropriate, federal interconnection standards."

On June 9, 2008, the Commission issued an Order revising North Carolina's Interconnection Standard. The Commission used the federal standard as the starting point for all state-jurisdictional interconnections (regardless of the size of the generator), and made modifications to retain and improve upon the policy decisions made in 2005. The Commission's Order required regulated utilities to update any affected rate schedules, tariffs, riders, and service regulations to conform with the revised standard.

On July 9, 2008, Duke filed a motion for reconsideration regarding whether an external disconnect switch should be required for certified inverter-based generators up to 10 kW. On December 16, 2008, the Commission issued an Order in which it granted Duke's motion for reconsideration and gave electric utilities the discretion to require external disconnect switches for all interconnecting generators. However, if a utility requires such a switch for a certified, inverter-based generator under 10 kW, the utility shall reimburse the generator for all costs related to that installation.

Net Metering

"Net metering" refers to a billing arrangement whereby a customer that owns and operates an electric generating facility is billed according to the difference over a billing period between the amount of energy the customer consumes and the amount of energy it generates. In Senate Bill 3, codified at G.S. 62.133.8(i)(6), the General Assembly required the Commission to consider whether it is in the public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one megawatt or less.

On March 31, 2009, following hearings on its then-current net metering rule, the Commission issued an Order requiring Duke, NC Power, and Progress to file revised riders or tariffs that allow net metering for any customer that owns and operates a renewable energy facility that generates electricity with a capacity of up to one megawatt. The customer shall be required to interconnect pursuant to the approved generator interconnection standard, which includes provisions regarding the study and implementation of any improvements to the utility's electric system required to accommodate the customer's generation, and to operate in parallel with the utility's electric distribution system. The customer may elect to take retail electric service pursuant to any rate schedule available to other customers in the same rate class and may not be assessed any standby, capacity, metering, or other fees other than those approved for all customers on the same rate schedule. Standby charges shall be waived, however, for any net-metered residential customer with electric generating capacity up to 20 kW and any net-metered non-residential customer up to 100 kW. Credit for excess electricity generated during a monthly billing period shall be carried forward to the following monthly billing period, but shall be granted to the utility at no charge and the credit balance reset to zero at the beginning of each summer billing season. If the customer elects to take retail electric service pursuant to any time-of-use

(TOU) rate schedule, excess on-peak generation shall first be applied to offset on-peak consumption and excess off-peak generation to offset off-peak consumption; any remaining on-peak generation shall then be applied against any remaining off-peak consumption. If the customer chooses to take retail electric service pursuant to a TOU-demand rate schedule, it shall retain ownership of all RECs associated with its electric generation. If the customer chooses to take retail electric service pursuant to any other rate schedule, RECs associated with all electric generation by the facility shall be assigned to the utility as part of the net metering arrangement.

10. FEDERAL ENERGY INITIATIVES

Open Access Transmission Tariff

In April 1996, the FERC issued Order Nos. 888 and 889, which established rules governing open access to electric transmission systems for wholesale customers and required the construction and use of an Open Access Same-time Information System (OASIS) for reserving transmission service. In Order No. 888, the FERC also required utilities to file standard, non-discriminatory OATTs under which service is provided to wholesale customers such as electric cooperatives and municipal electric providers. As part of this decision, the FERC asserted federal jurisdiction over the rates, terms, and conditions of the transmission service provided to retail customers receiving unbundled service while leaving the transmission component of bundled retail service subject to state control. In Order No. 889, the FERC required utilities to separate their transmission and wholesale power marketing functions and to obtain information about their own transmission system for their own wholesale transactions through the use of an OASIS system on the Internet, just like their competitors. The purpose of this rule was to ensure that transmission owners do not have an unfair advantage in wholesale generation markets.

Regional Transmission Organizations (RTOs)

In December 1999, the FERC issued Order No. 2000 encouraging the formation of RTOs, independent entities created to operate the interconnected transmission assets of multiple electric utilities on a regional basis. In compliance with Order No. 2000, Duke, Progress, and SCE&G filed a proposal to form GridSouth Transco, LLC (GridSouth), a Carolinas-based RTO. The utilities put their GridSouth-related efforts on hold in June 2002, citing regulatory uncertainty at the federal level. The GridSouth organization was formally dissolved in April 2005.

Dominion, NC Power’s parent, filed an application with the Commission on April 2, 2004, in Docket No. E-22, Sub 418, seeking authority to transfer operational control of its transmission facilities located in North Carolina to PJM Interconnection, an RTO headquartered in Pennsylvania. The Commission approved the transfer subject to conditions on April 19, 2005.

The Commission has continued to provide oversight over NC Power and PJM by using its own regulatory authority, through regional cooperation with other state commissions, and by participating in proceedings before the FERC. Together with the other state commissions with jurisdiction over utilities in the PJM area, the Commission is involved in the activities of the Organization of PJM States, Inc. (OPSI).

Transmission Rate Filings

In 2010, the Commission and the Public Staff jointly intervened in an NC Power transmission rate case before the FERC, arguing that some transmission costs should not be passed on to all transmission customers. Specifically, the Commission and the Public Staff argued that North Carolina citizens should not be required to pay the incremental cost of undergrounding several electric transmission lines located in Virginia when viable overhead options were available. On September 17, 2012, the Commission joined with NCEMC, Old Dominion Electric Cooperative, and the Virginia Municipal Electric Association No. 1 to file a reply brief in this case, which remains pending before the FERC.

Energy Policy Act of 2005

The Energy Policy Act of 2005 (EPAct 2005), which became law on August 8, 2005, gave the FERC responsibility to oversee mandatory, enforceable reliability standards for the bulk power system. In the summer of 2006, it approved the NERC as the entity responsible for proposing, for FERC review and approval, standards to protect the reliability of the bulk power system. NERC may delegate certain responsibilities to “Regional Entities” subject to FERC approval. In the southeast, those responsibilities, including auditing for compliance, have been delegated to the Southeastern Electric Reliability Corporation (SERC), headquartered in Charlotte, North Carolina. In March 2007, the FERC approved the first set of mandatory, enforceable reliability standards. Violations can result in monetary penalties of up to $1 million per day per violation. The FERC, NERC, and SERC have focused especially on two compliance areas that have been implicated in large regional bulk power system outages: (1) the need for more thorough vegetation management below and near high-voltage power lines and (2) the need for more rigorous design and maintenance of the relays that determine whether the electric grid “rides through” disturbances or “separates,” potentially contributing to cascading outages. More stringent federal requirements for vegetation management have reduced the flexibility North Carolina utilities have traditionally exercised in working with communities and landowners.

EPAct 2005 added a new Section 216 to the Federal Power Act, providing for federal siting of interstate electric transmission facilities under certain circumstances. States retain primary jurisdiction to site transmission facilities, and federal transmission siting effectively supplements a state siting regime. Section 216 requires the Secretary of the U.S. Department of Energy (DOE) to study electric transmission congestion and to designate, as a national interest electric transmission corridor, any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers. The DOE is required to prepare a report to Congress every three years on the status of transmission congestion nationwide. On November 10, 2011, the DOE announced its plan for conducting a 2012 Congestion Study. The report has not yet been issued.

Section 216 also authorized the FERC to site transmission facilities if a state withholds approval of a project for more than one year. The FERC interpreted this provision to include instances where a state has denied a proposed project. This interpretation was appealed to the United States Court of Appeals for the Fourth Circuit, which in 2009 ruled that the FERC had, in fact, interpreted the law too broadly.

EPAct 2005 required the FERC to establish incentive-based wholesale rate treatments for transmission facilities. Congress specified that these incentives were "for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." In July 2006, the FERC issued Order No. 679, which allows utilities to seek wholesale rate incentives such as: (1) incentive rates of return on equity for new investment in transmission facilities; (2) full recovery of prudently incurred transmission-related construction work in progress costs in rate base; and (3) full recovery of prudently incurred pre-commercial operation costs. The FERC allows these incentives based on a case-by-case analysis of individual transmission projects. The Commission has intervened in incentive proceedings before the FERC and has joined an appeal before the DC Circuit Court of Appeals in order to protect the interests of North Carolina consumers.

Cyber Security

Federal regulators are increasingly concerned about cyber security and physical threats to the nation's bulk power system. Cyber security threats may be posed by foreign nations or others intent on undermining the United States' electric grid. North Carolina's utilities are working to comply with federal standards that require them to identify critical components of their infrastructure and install additional protections from cyber attacks. The FERC believes its legal authority is inadequate to address potential threats to the bulk power system and has asked Congress to enact legislation to address this deficiency. In addition, NERC is leading an effort to develop more stringent cyber security standards.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of 2012 Biennial Integrated Resource Plans and Related 2012 REPS Compliance Plans	))))	ORDER APPROVING INTEGRATED RESOURCE PLANS AND REPS COMPLIANCE PLANS

HEARD: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on February 11, 2013

Courtroom 5310, Mecklenburg County Courthouse, 832 E. Fourth Street, Charlotte, North Carolina on February 28, 2013

BEFORE: Commissioner Bryan E. Beatty, Presiding; Chairman Edward S. Finley, Jr., and Commissioners William T. Culpepper, III, Susan W. Rabon, ToNola D. Brown-Bland, and Lucy T. Allen

APPEARANCES:

For Virginia Electric and Power Company, d/b/a Dominion North Carolina Power:

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For Duke Energy Progress, Inc., and Duke Energy Carolinas, LLC:

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For North Carolina Waste Awareness & Reduction Network, Blue Ridge Environmental Defense League, and Greenpeace:

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Timothy R. Dodge, Lucy E. Edmondson, and Robert S. Gillam, Staff Attorneys, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: Integrated Resource Planning (IRP) is intended to identify those electric resource options that can be obtained at least cost to the utility and its ratepayers consistent with the provision of adequate, reliable electric service. IRP considers demand-side alternatives, including conservation, efficiency, and load management, as well as supply-side alternatives in the selection of resource options. Commission Rule R8-60 defines an overall framework within which the IRP process takes place in North Carolina. Analysis of the long-range need for future electric generating capacity pursuant to G.S. 62-110.1 is included in the Rule as a part of the IRP process.

General Statute (G.S.) 62-110.1(c) requires the Commission to “develop, publicize, and keep current an analysis of the long-range needs” for electricity in this State. The Commission's analysis should include: (1) its estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix, and general location of generating plants; and (4) arrangements for pooling power to the extent not regulated by the Federal Energy Regulatory Commission (FERC). Further, G.S. 62-110.1 requires the Commission to consider this analysis in acting upon any petition for the issuance of a certificate for public convenience and necessity for construction of a generating facility. In addition, G.S. 62-110.1 requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly a report of its: (1) analysis and plan; (2) progress to date in carrying out such plan; and (3) program for the ensuing year in connection with such plan. G.S. 62-15(d) requires the Public Staff to assist the Commission in making its analysis and plan pursuant to G.S. 62-110.1.

G.S. 62-2(a)(3a) declares it a policy of the State to:

> assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills . . . .

Session Law (S.L.) 2007-397 (Senate Bill 3), signed into law on August 20, 2007, amended G.S. 62-2(a) to add subsection (a)(10) that provides that it is the policy of North Carolina "to promote the development of renewable energy and energy efficiency through the implementation of a Renewable Energy and Energy Efficiency Portfolio Standard (REPS)" that will: (1) diversify the resources used to reliably meet the energy needs of North Carolina's consumers, (2) provide greater energy security through the use of indigenous energy resources available in North Carolina, (3) encourage private investment in renewable energy and energy efficiency, and (4) provide improved air quality and other benefits to the citizens of North Carolina. To that end, Senate Bill 3 further provides that "[e]ach electric power supplier to which G.S. 62-110.1 applies shall include an assessment of demand-side management and energy efficiency in its resource plans submitted to the Commission and shall submit cost-effective demand-side management and energy efficiency options that require incentives to the Commission for approval."[1]

Senate Bill 3 also defines demand-side management (DSM) as "activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electric use from peak to nonpeak demand periods" and defines an energy efficiency (EE) measure as "an equipment, physical or program change implemented after 1 January 2007 that results in less energy being used to perform the same function."[2] EE measures do not include DSM.

To meet the requirements of G.S. 62-110.1 and G.S. 62-2(a)(3a), the Commission conducts an annual investigation into the electric utilities' IRPs. Commission Rule R8-60 requires that each utility, to the extent that it is responsible for procurement of any or all of its individual power supply resources (collectively, the utilities),[3] furnish the Commission with a biennial report in even-numbered years that

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[1] G.S. 62-133.9(c).

[2] G.S. 62-133.8(a)(2) and (4).

[3] During the 2013 Session, the General Assembly enacted S.L. 2013-187 (House Bill 223), which exempted the EMCs from the requirements of G.S. 62-110.1(c) and G.S. 62-42, effective July 1, 2013.

contains the specific information set out in that Rule. In odd-numbered years, each of the electric utilities must file an annual report updating its most recently filed biennial report.

Further, Commission Rule R8-67(b) requires any electric power supplier subject to Rule R8-60 to file a REPS compliance plan as part of each biennial and annual report. In addition, each biennial and annual report should (1) be accompanied by a short-term action plan that discusses those specific actions currently being taken by the utility to implement the activities chosen as appropriate per the applicable biennial and annual reports and (2) incorporate information concerning the construction of transmission lines pursuant to Commission Rule R8-62(p).

Within 150 days after the filing of each utility's biennial report and within 60 days after the filing of each utility's annual report, the Public Staff or any other intervenor may file its own plan or an evaluation of, or comments on, the utilities' biennial and annual reports. Furthermore, the Public Staff or any other intervenor may identify any issue that it believes should be the subject of an evidentiary hearing. The Commission must schedule one or more hearings to receive public testimony.

2012 BIENNIAL REPORTS

This Order addresses the 2012 biennial reports (2012 IRPs) filed in Docket No. E-100, Sub 137, by Duke Energy Progress, Inc. (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (DNCP) (collectively, the investor-owned utilities or IOUs), and North Carolina Electric Membership Corporation (NCEMC),[4] Rutherford EMC (Rutherford), Piedmont EMC (Piedmont), Haywood EMC (Haywood), and EnergyUnited EMC (EnergyUnited) (collectively, the electric membership corporations or EMCs).[5] In addition, this Order addresses the REPS compliance plans filed by the lOUs, GreenCo,[6] Halifax EMC (Halifax), and EnergyUnited.

As a result, EMCs are no longer subject to the requirements of Rule R8-60 and are no longer required to submit IRPs to the Commission for review.

[4] NCEMC indicated that it provides wholesale power to 25 of the 26 EMCs in North Carolina and is the full requirements power supplier for 20 of the cooperatives. NCEMC's 2012 IRP is filed on behalf of these 20 members. NCEMC provides partial requirements capacity and energy entitlements to 5 EMCs: Blue Ridge EMC, Rutherford EMC, Piedmont EMC, Haywood EMC, and EnergyUnited (collectively, the independent EMCs). The 26th EMC, French Broad EMC, is not a member of NCEMC and is not required to file an individual IRP, as it has entered into a full requirements contract with DEP.

[5] Blue Ridge EMC contracts with DEC as its full requirements and REPS compliance service provider. Blue Ridge EMC, therefore, is not required to file an IRP.

[6] GreenCo filed a consolidated 2012 REPS compliance plan on behalf of Albemarle EMC, Brunswick EMC, Cape Hatteras EMC, Carteret-Craven EMC, Central EMC, Edgecombe-Martin County EMC, Four County EMC, French Broad EMC, Haywood, Jones-Onslow EMC, Lumbee River EMC, Pee Dee EMC, Piedmont, Pitt & Greene EMC, Randolph EMC, Roanoke EMC, South River EMC, Surry-Yadkin EMC, Tideland EMC, Tri-County EMC, Union EMC, and Wake EMC.

The following parties intervened in this docket: Blue Ridge Environmental Defense League (BREDL); Carolina Industrial Group for Fair Utility Rates I, II, and III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); Greenpeace; Mid-Atlantic Renewable Energy Coalition (MAREC); North Carolina Sustainable Energy Association (NCSEA); North Carolina Waste Awareness and Reduction Network (NC WARN); Sierra Club; and Southern Alliance for Clean Energy (SACE). The Public Staff's intervention is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

PROCEDURAL HISTORY

On August 8, 2012, Rutherford filed a letter indicating that its load would be included in DEC's IRP filing for reporting purposes, and its REPS compliance plan would be reflected in DEC's REPS compliance plan. On August 30, 2012, EnergyUnited filed its 2012 IRP and 2012 REPS compliance plan. On August 31, DNCP filed its 2012 IRP and 2012 REPS compliance plan, and Rutherford filed its 2012 IRP. On September 4, 2012, DEC[7] and DEP filed their 2012 IRPs and 2012 REPS compliance plans, NCEMC filed its 2012 IRP, and GreenCo and Halifax filed their 2012 REPS compliance plans. On September 11, 2012, Piedmont filed its 2012 IRP, and on September 13, 2012, Haywood filed its 2012 IRP. On November 11, 2012, DNCP filed an amendment to its 2012 IRP.

On October 8, 2012, the Commission issued an Order scheduling a public hearing on the 2012 IRPs and the 2012 REPS compliance plans for February 11, 2013, in Raleigh.

On January 10, 2013, the Public Staff filed a motion requesting that the deadline for the filing of comments on the 2012 IRPs and REPS compliance plans be extended to February 5, 2013, which the Commission granted by Order dated January 15, 2013. This Order also extended the deadline for reply comments to February 19, 2013.

On February 4, 2013, BREDL, Greenpeace, and NC WARN (NC WARN, et al.) submitted their joint comments on the 2012 IRPs. On February 5, 2013, comments on the 2012 IRPs were submitted by the Public Staff, MAREC, NCSEA, and jointly by SACE and the Sierra Club. On February 7, 2013, MAERC filed an amended version of its initial comments.

On February 15, 2013, DEC and DEP filed a motion for extension of time to file reply comments until March 5, 2013, which the Commission granted by Order issued on February 18, 2013.

On March 5, 2013, reply comments were filed by Halifax, Rutherford, SACE, DNCP, EnergyUnited, NCEMC, and jointly by DEC and DEP.

[7] DEC's REPS compliance plan included the REPS compliance plans for Rutherford and Blue Ridge EMC.

On July 15, 2013, the Commission issued an Order which, among other things, called for the filings of proposed orders and briefs in this docket on or before August 26, 2013.

On July 22, 2013, NCSEA filed a partial proposed order limited to the issue of access to electricity consumption data that it had raised in its initial comments.

On August 21, 2013, the Public Staff filed a motion requesting an extension of time to September 9, 2013, for the filing of briefs and proposed orders, which was granted by the Commission on August 22, 2013.

On September 6, 2013, NC WARN, et al., filed its brief. On September 9, 2013, SACE and the Sierra Club filed a joint brief, MAREC filed a brief, and the Public Staff, DNCP, and DEC and DEP jointly filed proposed orders.

NC WARN et al.'s Motion for Additional Public Hearings

On January 9, 2013, NC WARN, et al., filed a motion requesting that the Commission hold additional public hearings in Charlotte and Asheville. NC WARN, et al., stated, among other things, that there was considerable public interest in the IRPs in Charlotte and Asheville, that members of those communities felt it would be a hardship to attend the public hearing in Raleigh, and that a single public hearing would not provide adequate time to hear from all interested persons.

On January 24, 2013, the Commission issued an Order allowing responses to the motion for additional hearings. On January 31, 2013, SACE and the Sierra Club filed a joint response supporting the motion for additional hearings. On February 1, 2013, DEC and DEP filed a joint response stating that there was no need to hold additional IRP public hearings, since several avenues existed for members of the public to express their views about the IRPs, including the public hearing in Raleigh, letters, petitions, and electronic mail. They also stated that NC WARN, et al.'s position on the construction and operation of generating facilities is well documented and additional public hearings would result in needless repetition of the same talking points, and that if the Commission decided to grant NC WARN, et al.'s motion, it should schedule one hearing to be held in a location that is central to both Charlotte and Asheville, such as Hickory.

On February 5 and 6, 2013, the Commission granted NC WARN, et al.'s motion in part by scheduling one public hearing to be held in Charlotte, North Carolina on February 28, 2013.

NC WARN, et al.'s Motion for an Evidentiary Hearing

In their initial joint comments filed on February 4, 2013, NC WARN, et al. requested that the Commission hold an evidentiary hearing on whether the IRPs submitted by DEC and DEP are in the best interest of ratepayers and provide “least cost” electricity. In their initial joint comments, SACE and the Sierra Club indicated their support for an evidentiary hearing and proposed issues on which the Commission might wish to receive pre-filed testimony and conduct a hearing. In their March 5, 2013, reply comments, the IOUs indicated that they did not view NC WARN, et al.'s request for an evidentiary hearing as presenting compelling issues or reasoning in support of such a hearing, and that the request for an evidentiary hearing should be denied.[8]

On May 3, 2013, the Commission issued an Order Requiring Verified Responses in which it noted that during the public hearings, as well as in statements of position regarding this proceeding that were mailed or emailed to the Commission, many citizens questioned whether the IRPs filed by DEC and DEP appropriately reflect the expected growth in demand for electricity, the ability to meet that demand with EE and renewable energy resources, and other aspects of the IRPs. As a result of these concerns, as well as information from other proceedings and forums, the Commission found good cause to require DEC and DEP to provide verified answers on or before Monday, June 10, 2013, to 19 questions listed on Attachment A to its Order. The topics covered by the questions included EE, DSM, renewable energy, tiered electric rates, public benefit loan funding, solar generation, future EE potential, full compliance with REPS requirements, population growth projections, projected annual retail load growth, generation reserve margins, coal plant emissions and climate change initiatives.

On May 13, 2013, NC WARN, et al., filed a response to the Commission's Order stating, among other things, that the questions included in the Order helped to shed light on several issues not covered in the IRPs. In addition, NC WARN, et al. proposed that two additional questions be added to the list of Commission questions. The proposed questions asked whether DEC and DEP had conducted a study of the potential for using combined heat and power (CHP). Further, NC WARN, et al. stated that it continued to urge the Commission to hold an evidentiary hearing in this docket.

On June 10, 2013, DEC and DEP filed a combined verified response to the Commission's 19 questions.

On July 15, 2013, the Commission issued an Order denying NC WARN, et al.’s motion for an evidentiary hearing. In its Order, the Commission concluded that the substantive issues raised by ratepayers in their testimony and written comments and by the intervenors in their initial comments have been addressed by DEC and DEP in their respective reply comments and in their responses to the Commission's Order Requiring Verified Responses. In addition, the Commission concluded that the record contains sufficient detail to allow the Commission to decide all contested issues without the necessity of a further evidentiary hearing, and that there is not good cause to require DEC and DEP to answer the additional questions proposed by NC WARN, et al.

[8] DEC and DEP reply comments at 11; DNCP reply comments at 13.

NCSEA's Motion for Disclosure

On February 5, 2013, NCSEA filed a motion for disclosure requesting that the Commission require DEC and DEP to make public certain information in their REPS compliance plans that was filed under seal with the Commission as confidential trade secret information. In addition, NCSEA requested that the Commission order DEC, DEP, and DNCP to annually review their REPS compliance plans from four years earlier and make public all information that was previously redacted from those plans, or file an explanation of why the information should remain confidential. On February 7, 2013, the Commission issued an Order requesting that interested parties file comments and reply comments in response to NCSEA's motion. On March 7, 2013, initial comments were filed jointly by DEC and DEP. On March 8, 2013, initial comments were filed jointly by SACE and the Sierra Club, and individually by DNCP. On March 25, 2013, NCSEA filed reply comments and on April 1, 2013, DNCP filed reply comments.

On June 3, 2013, the Commission issued an Order granting NCSEA's motion in part by (1) ordering DEP to amend its 2012 REPS compliance plan by filing as public information the specific REPS contract information disclosed in Exhibit 1 of DEP's 2008 and 2010 REPS compliance plans, to the extent that this information has not changed and continues to be a part of DEP's 2012 REPS compliance plan, and further, to include this specific contract information in its subsequent REPS compliance plans under the same guidelines; (2) ordering DEC to amend its 2012 REPS compliance plan by disclosing the information redacted in its 2008 REPS compliance plan, subject to prohibitions in the contracts and after redacting the names of counterparties; (3) ordering DEP, DEC, and DNCP to annually review their REPS compliance plans from four years earlier and disclose any redacted information that is no longer a trade secret; and (4) reaffirming the guidelines stated in the Commission's Order Concerning Confidentiality of Report Filings in Docket No. P-100, Sub 133, issued on October 21, 1997, which required parties to submit at the time of filing information under seal a detailed and cogent statement of the reasons the information is a trade secret pursuant to G.S. 132-1, et seq. On July 1, 2013, DEC filed revised 2008 and 2012 REPS compliance plans.

NCSEA Request for Rulemaking

In its initial comments, NCSEA requested that the Commission find that there is an inadequacy of access to customer information, that this inadequacy impedes the greater utilization of DSM/EE, and that the Commission should open a rulemaking docket to expand access to customer data, both to the customers of the electric power suppliers and third parties, such as smart grid technology companies, at the meter level and the aggregate level. NCSEA stated that the rule changes could potentially enable:

(1) Academic and governmental institutions to conduct research, the results of which will help educate society about energy usage;
(2) Businesses to develop and roll out innovative energy usage products and services; and

(3) Customers to exercise greater control over their energy usage and its economic, environmental, and social impacts.[9]

NCSEA stated that Commission Rule R8-51 may be antiquated and not accurately reflect, for example, the availability of more granular data than monthly usage or customer interest in accessing their electricity consumption data via the internet. NCSEA pointed out that the National Association of Regulatory Utility Commissioners (NARUC) and the American Council for an Energy Efficient Economy (ACEEE) have called for promulgation of rules that contemplate such issues, and numerous states have adopted rules that increase the availability of this information while maintaining the privacy of customer information in the absence of disclosure authorization.[10]

In its reply comments, DNCP disputed the need for a rulemaking proceeding and noted that expansion of access to customer information in the manner suggested by NCSEA should be handled with caution. DNCP noted that customers can be provided greater access than required by Rule R8-51, subject to conformance with DNCP's Code of Conduct, and also can access up to 18 months of historical usage data online or by telephone. In addition, with the customer's written consent, a customer may have his billing information released to a third party, or he may retrieve the information online and provide it to a third party. Further, DNCP stated that it cannot technically comply with NCSEA's suggestion of customer access to a "timely stream" of consumption data, since many of DNCP's North Carolina customers do not have automated metering technology.[11]

In their reply comments, DEC and DEP echoed some of the same concerns raised by DNCP regarding the importance of protecting customer information. DEC and DEP further stated that they have engaged in an ongoing dialogue with NCSEA and the Public Staff about customer data issues and "would not object to a separate rulemaking proceeding to explore customer data access if the Commission deems it advisable."[12]

SACE and the Sierra Club supported initiation of a rulemaking to examine the issue of access to customer data and to make appropriate changes.

In addition to the comments filed by intervenors, various parties, including trade associations, local governments, state agencies, nonprofits, and academic institutions, filed statements of position in support of NCSEA's request that the Commission open a separate rulemaking docket to review and modernize the rules governing access to customer energy usage data.

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[9] NCSEA second comments on March 8, 2013.

[10] NCSEA initial comments at 14, 18, 21, 26, 27.

[11] DNCP reply comments at 12.

[12] DEC and DEP reply comments at 12.

On August 23, 2013, the Commission issued an Order Requesting Additional Information and Declining to Initiate Rulemaking. In regard to NCSEA's contention that there is a current inadequacy of access to customer information, the Commission declined to make the requested finding on two grounds. First, the Commission noted that in its Order Declining to Adopt Federal Standards, issued on December 18, 2009, in Docket No. E-100, Sub 123, it had declined to adopt the federal standard for smart grid information set forth in Section 111(d)(19)(A)-(C) of the Public Utility Regulatory Policies Act (PURPA) because it found that the utilities were generally providing sufficient access to customer data, which the Commission expected to increase as smart grid technologies are implemented. The Commission also encouraged the utilities to investigate making real time pricing available to all customers and to update time-of-use (TOU) rates. The Commission also noted that in its May 30, 2013, Order Granting General Rate Increase in Docket No. E-2, Sub 1023, it had ordered DEP to complete a study regarding TOU rates and report the results to the Commission. Further, the Commission noted that Commission Rules R8-60 and 60.1 require IOUs to report certain information regarding access to customer information as they implement smart grid technology.

The Commission also disagreed with NCSEA's contention that there is an inadequacy of access to customer information based on Commission Rule R8-51, which the Commission noted is intended to provide customers with full access to all their usage data that is available. The Commission agreed with NCSEA that the availability of electronic and real time data from the IOUs should be clarified and ordered the IOUs to respond to questions regarding access to and availability of electronic and real time data.

As the Commission did not agree with NCSEA that there was an inadequacy of data or lack of customer access to such data, the Commission also declined to find that an inadequacy of data was an impediment to utilization of DSM/EE. Moreover, the Commission did not find that there was a clear linkage between access to customer data and utilization of DSM/EE, as there are a number of other variables that are barriers to greater implementation of EE.

In regard to NCSEA's request that the Commission initiate a rulemaking, the Commission found that such an investigation would be premature as there were insufficient details regarding consumption data that would be available in the future. The Commission indicated that it was inclined to wait until after the filing of the IOUs' smart grid reports on October 1, 2014. The Commission's August 23, 2013 Order also directed DEC, DEP and DNCP to file verified responses to questions listed on Attachment A of the Order by September 23, 2013.

On September 23, 2013, DEC, DEP and DNCP filed verified responses to the Commission's questions.

Public Hearings

Pursuant to G.S. 62-110.1(c), the Commission held two public hearings to take public witness testimony regarding the filed 2012 IRPs and 2012 REPS compliance plans. The first hearing was held on Monday, February 11, 2013, in Raleigh, North Carolina, where 43 public witnesses spoke. The second hearing was held on Thursday, February 28, 2013, in Charlotte, North Carolina, where 70 public witnesses spoke. The witnesses at both hearings discussed a wide range of issues, including the impact of coal-fired electricity generation, the threat of climate change, alternative models for establishing utility rate structures, the reasonableness of utility load growth forecasts, and the opportunities for increased uses of alternative resources such as wind, solar energy, and EE. During the course of this proceeding, the Commission also received over 2,500 letters or emails from customers, generally expressing concern over the utilities' continued reliance on fossil-fueled generation and support for increased use of renewable energy and EE.

Based on the foregoing, the comments of the parties, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. The IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and should be approved.

2. The 2012 IRP biennial reports submitted by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited and Haywood are reasonable and should be approved.

3 DEC and DEP complied with the Regulatory Conditions related to least-cost integrated resource planning imposed in the Commission's Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued June 29, 2012, in Docket Nos. E-2, Sub 998, and E-7, Sub 986 (Merger Order), approving the business combination of Duke Energy Corporation and Progress Energy, Inc., pursuant to G.S. 62-111(a).

4. DEC and DEP should continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to modify this process by Commission order or until a combination of the utilities is approved by the Commission.

5. The IOUs and EMCs included a full discussion of their DSM programs and their use of these resources as required by Rule R8-60(i)(6).

6. The IOUs included in their IRPs a discussion of their market potential studies, including updates, for DSM and EE programs.

7. The IOUs and EMCs provided sufficient details of their investigations of the value of activating their current DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources.

8. The IOUs and EMCs adequately discussed the consumer education programs they currently provide to their customers, or propose to implement within the biennium.

9 The IOUs included in their IRPs a discussion of measures to inform all customers of their system summer peaks so that they might engage in voluntary demand response and peak shaving.

10. The IOUs and EMCs included in their IRPs a discussion regarding the impacts of smart grid deployment on their IRPs.

11. The IOUs provided an adequate assessment of alternative supply-side resources.

12. The IOUs should continue to include a full discussion of alternative supply-side resources in future IRPs to evaluate the potential impacts of these resources on their system.

13. The process used by the IOUs to evaluate resource options and selecting the least cost portfolio is reasonable.

14. DEP and DEC have adequately addressed the issues raised by Sierra Club, SACE, and NC WARN, et al., in this proceeding, including the proper evaluation of EE and DSM resources, least cost portfolio selection, peak demand and energy growth projections, baseload requirements, the cost of new nuclear generation, greenhouse gas emissions, and the potential economic viability of existing scrubbed coal units.

15. The Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is a reasonable path for DEC's compliance with the carbon emission reduction standards of its air quality permit.

16. DEC should continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

17. The 2012 REPS compliance plans submitted by the IOUs, GreenCo, EnergyUnited and Halifax are reasonable and should be approved.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

Load Forecasts

In its comments, the Public Staff stated that all of the utilities use accepted econometric and end-use analytical models to forecast their peak and energy needs. The Public Staff noted that, as with any forecasting methodology, there is a degree of uncertainty associated with models that rely, in part, on assumptions that certain historical trends or relationships will continue in the future.

The Public Staff indicated that it reviewed the utilities' 15-year peak and energy forecasts (2013–2027). According to the Public Staff, the compound annual growth rates (CAGRs) for the forecasts of DEC, DEP, and DNCP were within the range of 0.9% to 1.7%, while the CAGRs for NCEMC and the four EMCs that filed IRPs were within the range of 0.9% to 1.9%. The Public Staff also briefly discussed the load reductions achieved by utilities' DSM and EE programs.

DEP

DEP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 0.9%, as compared to 1.6% in its 2011 IRP. Without consideration of the effects of its DSM and EE programs, DEP expects its summer peaks to grow at 1.2%. The average annual growth of its summer peak, which is considered its system peak, is 130 megawatts (MW) for the next 15 years, as compared to 201 MW in the 2011 IRP. DEP predicts that load reductions from its DSM programs will reduce its peak load by approximately 9% in 2027.

DEP's energy sales are predicted to grow at a CAGR of 1.0%, a 0.3% decrease from the projected growth rate in the 2011 IRP. DEP predicts that the megawatt-hour (MWh) reductions from its EE programs will reduce its energy sales by approximately 4% in 2027.

DEP's last annual system peak, 12,770 MW, occurred on Thursday, July 26, 2012, at the hour ending 5:00 p.m. At the time of the peak, DEP activated its EnergyWise Program and its Commercial, Industrial, and Government Demand Response Program, which reduced its peak load by 101 MW and 16 MW, respectively. DEP's 2011 IRP projected that it would have 803 MW available from its DSM programs to reduce its 2012 summer peak. DEP activated 117 MW of DSM in 2012.

DEC

DEC's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.7%, 0.1% lower than projected in the 2011 IRP. Prior to the implementation of its DSM and EE programs, DEC expects its summer peaks to grow at 2.0%. The average annual growth of its summer peak, which is considered its system peak, is 321 MW for the next 15 years, as compared to 351 MW from last year's IRP. DEC predicts that load reductions from its DSM programs will reduce its peak load by approximately 10% in 2027.

DEC's energy sales are expected to grow at a CAGR of 1.7%. This growth rate in energy sales is 0.1% less than predicted in the 2011 IRP. DEC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 5% in 2027.

DEC's last annual system peak, 17,740 MW, occurred on Thursday, July 26, 2012, at the hour ending 5:00 p.m. DEC activated approximately 130 MW of DSM programs to lower the peak. DEC's 2011 IRP projected the availability of 838 MW from its DSM programs to reduce its 2012 summer peak.

DNCP

DNCP's 15-year forecast predicts that its summer peaks will grow at a CAGR of 1.5%, which is a 0.1% increase from the projected growth rate in the 2011 IRP. The average annual growth of its summer peak, which is considered its system peak, is 285 MW for the next 15 years, as compared to 274 MW in the 2011 IRP. DNCP predicts that load reductions from its DSM programs will reduce its 2027 peak load by approximately 2%.

DNCP's energy sales are predicted to grow at an average annual rate of 1.6%. This projected growth rate in energy sales is the same rate as the growth rate in the 2011 IRP. DNCP predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 3% in 2027.

DNCP's last annual system peak, 16,787 MW, occurred on Friday, June 29, 2012, at the hour ending 5:00 p.m. At the time of the summer peak, DNCP called on its Distributed Generation Pilot[13] for a load reduction of 5 MW and its Air Conditioning Cycling Program for a reduction of 53 MW. DNCP's 2011 IRP projected the availability of 45 MW from its DSM programs to reduce its 2012 summer peak.

NCEMC

NCEMC's 15-year forecast predicts that its summer peaks will grow at an average annual rate of 1.4%, a decrease of 0.2% from the predicted growth rate in its 2011 IRP. The average annual growth of its summer peak, which is considered its system peak, is 48 MW.

NCEMC's last annual system peak, 3,121 MW, occurred on Wednesday, January 4, 2012, at the hour ending 7:00 a.m., which is comparable to 2011 when the system peaked at 2,982 MW on January 14 at 8:00 a.m. NCEMC's 2011 IRP projected that 52 MW would be available from its DSM programs.

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[13] The Distributed Generation Pilot is a DSM program operating only in Dominion's Virginia jurisdiction.

NCEMC's energy sales are predicted to grow at an average annual rate of 1.4%, a decrease of 0.1% from the growth rate predicted in its 2011 IRP. NCEMC predicts that the MWh savings from its EE programs will reduce its energy sales by approximately 1% in 2027.

EnergyUnited

EnergyUnited's 15-year forecast predicts that its system peak will grow at an average annual rate of 0.9%. Its energy sales are predicted to grow at an average annual rate of 0.9%. The average annual growth of the annual peak is 6 MW over the 15-year forecast. EnergyUnited's annual peak, 573 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. EnergyUnited activated its DSM programs and reduced the load by 15 MW at the time of the peak.

Haywood

Haywood's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.8%. Its energy sales are predicted to grow at an average annual rate of 1.9%. The average annual growth of the annual peak is 2 MW over the 15-year period. Haywood's annual peak, 73 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. DEC, which has operational control of Haywood's DSM programs, did not activate the DSM programs at the time of Haywood's winter peak, but it did activate Haywood's DSM programs on two days during July 2012.

Piedmont

Piedmont's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.7%. The average annual growth of its peak is 3 MW over the 15-year period. Piedmont's energy sales are predicted to grow at an average annual rate of 1.7%. Piedmont's annual peak, 125 MW, occurred on Sunday, July 8, 2012, at the hour ending 5:00 p.m. At the time of its peak, Piedmont did not activate its DSM programs.

Rutherford

Rutherford's 15-year forecast predicts that its system peak will grow at an average annual rate of 1.1%. Its energy sales are predicted to grow at an average annual rate of 1.0%. The average annual growth of Rutherford's system peak is 4 MW over the 15-year period. Rutherford's annual peak, 309 MW, occurred on Wednesday, January 4, 2012, at the hour ending 8:00 a.m. DEC, which has operational control of Rutherford's DSM programs, did not activate any of the DSM programs at the time of Rutherford's winter peak, but it did activate Rutherford's DSM programs on four days during June and July 2012.

Summary of Load Forecasts

The following table prepared by the Public Staff summarizes the growth rates for the IOUs' and EMCs' system peak and energy sales forecasts based on their 2012 IRP filings.

2013 - 2027 Growth Rates

(After New EE and DSM)

	Summer Peak	Winter Peak	Energy Sales	Annual MW Growth
DEP	0.9%	1.2%	1.0%	130
DEC	1.7%	1.7%	1.7%	321
DNCP	1.5%	1.5%	1.6%	285
NCEMC	1.4%	1.4%	1.4%	48
EnergyUnited	1.2%	0.9%	0.9%	6
Haywood	1.8%	1.8%	1.9%	2
Piedmont	1.7%	1.7%	1.7%	3
Rutherford	1.1%	1.1%	1.0%	4

In general, the Public Staff concluded that the peak load and energy sales forecasts used by the utilities were reasonable for planning purposes. The Public Staff noted that among the IOUs both DEC's and DEP's forecasts predicted peak loads in excess of actual loads for the past five years and had peak load and energy sales forecast errors that were higher than those of DNCP. The Public Staff recommended that to the extent they have not already done so DEC and DEP should review their equations and other assumptions for possible refinement in order to reduce the possibility of overestimation bias in future load forecasts. In their reply comments, Sierra Club and SACE supported this recommendation. In their initial comments, NC WARN, et al., asserted that DEC and DEP have overestimated the growth in electric demand over the IRP planning horizon in order to justify the construction of new conventional power plants.

In their reply comments, DEC and DEP disputed the claims of NC WARN, et al., indicating that their IRPs present a robust and balanced portfolio over a range of sensitivities. DEC and DEP did not respond directly to NC WARN, et al.'s claim regarding overestimating growth in electric demand, except through incorporation by reference of their reply comments filed in IRP proceedings since 2006.

In its May 3, 2013, Order, the Commission stated that during the public hearings, as well as in comments regarding this proceeding that were mailed or e-mailed to the Commission, many citizens questioned whether the IRPs filed by DEC and DEP appropriately reflect the expected growth in demand for electricity, and directed DEC and DEP to provide verified answers to several questions related to load growth. In Request No. 3, the Commission asked questions regarding difference in projections in electric demand between DEC and DEP's service territory in North Carolina and forecasted electricity sales growth in Indiana and Ohio. In their June 10, 2013, verified responses, DEC and DEP indicated that based on the values used in their most recently filed IRPs in each jurisdiction, sales were projected to grow in all jurisdictions into the future. DEC and DEP further stated that variability in the rates was due to the following reasons:

- DEP, DEC, Duke Energy Ohio and Duke Energy Indiana have different local economies, population make up, retails sales environment, and weather patterns. The load forecasts for each area take into account these differences and they are reflected in the forecast results.
- The load forecasts also include the latest estimates of how sales are expected to respond to changes in key drivers such as economic indicators, population, end-use efficiencies, weather, and retail rates. Based on analysis, customer response to these drivers varies by state.
- Sales for some territories are expected to recover sooner while others are expected to recover later or more gradually, because each service area is in a slightly different state in the economic cycle/recovery as evidenced by trends in unemployment, income, and spending.
- The forecast impacts on load growth associated with incorporating utility sponsored EE programs or complying with a state commission's mandate vary by jurisdiction and the load forecasts show that include those impacts.[14]

In Requests No. 11 and 15, the Commission asked DEC and DEP to provide further justification for the significant volatility in retail sales load growth the utilities have experienced since 1996, including short periods of pronounced growth as well as declines, and to explain how they factored these recent experiences in load growth into their projected load growth in the planning period. The responses from both utilities pointed out the severe recession in 2008-2009 and the large structural decline in textiles

[14] DEC and DEP verified responses at 5.

having a significant impact on any growth estimates ending in 2011. The utilities stated that they relied on "long-term econometric models by class that relate kWh sales to factors such as weather, price of electricity, real income, as well as service area population projections. The coefficients from the long-term econometric models are then applied to the projections of the weather, economic, and population variables to arrive at the energy forecast."[15] Both utilities indicated that they believe the 1.4% (DEC) and 1.2% (DEP) forecasted load growth provided in their IRPs is reasonable for planning purposes.

In Request No. 12, the Commission asked DEC and DEP to explain a statement by then-President Jim Rogers quoted in the November 29, 2012, edition of the Charlotte Business Journal that the Company's load growth will be lower than projections in the economic models. The Company responded that Mr. Rogers was expressing his personal opinion and that the Company stands by the forecast included in its 2012 IRPs as an accurate forecast for the purpose of preparing the 2012 IRPs. These forecasts are updated annually and new forecasts will be reflected in the 2013 DEC and DEP IRPs."[16]

The Commission agrees with the Public Staff that all of the utilities used accepted econometric and end-use analytical models to forecast their peak and energy needs and recognizes the limitations of these models. Nonetheless, the Commission agrees with the Public Staff's recommendation that DEC and DEP continue to review their equations and other assumptions for possible refinement in order to reduce the possibility of overestimation bias in future load forecasts.

Reserve Margin Adequacy

For the planning period 2013 to 2027, the range of summer reserve margins reported by the electric utilities continues to be similar to those used in previous annual reports. For this time period, the reserve margins are:

Utility	Target Reserve Margin	Planned Reserve
DEP	14.5%	15% to 17%
DEC	15.5%	9.2% to 17.9%[17]
DNCP	11%	5.75% to 16.3%

[15] Id. at 14, 16.

[16] Id. at 15-16.

[17] DEC utilized a 20-year planning period, hence their planned reserve margins applies for the 2013-2032 period.

NCEMC indicates that all its purchases include reserves. Future purchases will also include reserves, or NCEMC will acquire reserves independently. The four independent EMCs have active contracts with DEC, DEP, and Southern Company, each requiring the EMCs to maintain reserves commensurate with the supplying electric utility. DEP's IRP indicates that DEP will meet its projected reserve margin targets for the planning period. The Public Staff stated that it considered the planned reserves of the electric power suppliers to be adequate.

DEC's IRP indicates that its reserve margins will drop below its target reserve margin percentages for short periods. DEC points out that significant solar generation is being added to its system. While this generation is not dispatchable, the generation primarily occurs during peak periods. Since the time of the filing of the 2012 IRPs, the interconnection of solar facilities has escalated for all electric suppliers in North Carolina due to the dramatic decrease in the cost of solar photovoltaic (PV) generation, the tax benefits available for renewable generation, and the requirements of the REPS in North Carolina. In addition, DEC's short short-term load growth appears to be lower than originally projected, and usage is lower, possibly due to economic conditions. Based on these factors and the relatively short time periods during which DEC's actual reserve margins fall below its target reserve margins, the Public Staff stated that it found DEC's planned reserves to be adequate. Nevertheless, the Public Staff recommended that DEC include the information required by Commission Rule R8-60(i)(3), which requires a specific explanation for instances when the projected reserve margin varies from the planning reserve margin by plus or minus 3%.

In its reply comments, DEC responded that the instances in which the projected reserve margin exceeded the target by more than 3% were due to "lumpiness" associated with new generation additions.[18] DEC indicated that the commencement of commercial operation of the Dan River Combined Cycle facility and Cliffside Unit 6 in the fall of 2012 caused an exceedance, but that the accelerated retirement of Buck Units 5-6 and Riverbend Units 4-7 in April 2013 reduced the planning reserve margin to be within 2% of the target reserve margin in 2014. DEC indicated that projected generation additions in 2019, 2022, and 2024 all cause similar exceedances, but that "there is a resource need in these years, that if not met, would require the reserve margin to dip below the target reserve margin."[19] DEC also noted that "while there are substantial increases in solar qualifying facility (QF) interconnection requests since the filing of the 2012 IRP, DEC feels that the solar projections utilized in the IRP adequately account for these additions." DEC stated that it is constantly monitoring the impact of these facilities to the system and will make adjustments to the plan going forward as necessary.[20]

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[18] DEC and DEP reply comments at 4.

[19] *Id*.

[20] *Id*.

DNCP participates in the PJM market and, through the RPM auction, has obtained a commitment for additional capacity purchases above and beyond the existing identified firm purchases so as to ensure that its reserve margins meet the target of 11% reserves in 2013 and thereafter.

Based on its review of the annual plans, the Public Staff found that the reserves listed are adequate, and recommended that DEC, DEP, and DNCP maintain their proposed reserve margins as filed.

In their initial comments, Sierra Club and SACE stated that DEC's "treatment of demand response raises concerns that DEC may be planning for excessive reserves."[21] Sierra Club and SACE noted that in DEP's reserve margin study, demand response was treated as a resource option, which did not require its own reserve requirements, while in the DEC study, demand response was treated as a resource option requiring backstand reserves. Sierra Club and SACE also noted that:

> For purposes of calculating reserve requirements, system generation resources (and net transactions with other systems) should be compared to net internal demand. As defined by the North American Electric Reliability Corporation (NERC), net internal demand includes unrestricted non-coincident peak adjusted for energy efficiency, diversity, stand-by demand, non-member load, and demand response.[22]

Sierra Club and SACE noted that while DEC has previously stated that some of its programs are not dispatchable or controllable, therefore requiring backstand reserves, data from DEC indicated that it had been able to activate these programs on numerous occasions and achieve results consistent with, or even in excess of, expected reductions. Sierra Club and SACE noted that DEP's method of accounting for demand response appears to be more consistent with the NERC guidelines, and recommended that, with the exception of its PowerManager (air conditioner) program, DEC should evaluate demand response programs for purposes of calculating reserve requirements as adjustments to net internal demand, similar to the method utilized by DEP.

In its May 3, 2013, Order Requiring Verified Responses, the Commission asked DEC and DEP in Requests No. 13 and 16, respectively, to indicate the date on which and by what amount the highest portion of the utility's reserve margin was utilized to serve its system retail requirements. In their June 10, 2013 replies, DEC indicated for the period 2006 through 2011, its lowest actual reserve margin was 2.2% and occurred on August 9, 2007, while DEP indicated that for the period from 2006 through 2011, the lowest actual reserve margin was 7.1% and occurred on August 6, 2008. DEC and DEP indicated that this actual reserve margin represents the operating reserve margin without impacts of DSM and curtailment riders. DEC and DEP further explained that

[21] Sierra Club and SACE initial comments at 61.

[22] *Id*. at 63.

> the planning reserve margin is developed to account for abnormalities in weather, unit availability, and load forecast error, whereas actual reserve margin reflects the actual impacts of these events. Accordingly, the actual reserve margin is expected to be substantially lower than the target planning reserve margin at times.[23]

In Requests No. 14 and 17, the Commission asked DEC and DEP whether either utility had conducted an analysis or study of the potential of using neighboring wholesale resources, such as generation owned by TVA or generation located in PJM, to supply some portion of its reserve margin. In their verified responses, DEC and DEP indicated that their 2012 generation reserve margin studies, both of which were prepared by Astrape Consulting, considered and included the benefit of being interconnected to neighboring utilities such as TVA, Southern, PJM, and SCANA. DEC and DEP both indicated that their reserve margin requirements would have been substantially higher in their studies had these neighboring wholesale resources not been taken into account.[24]

The Commission agrees with the Sierra Club and SACE that in future reserve margin studies DEC should consider demand response programs that it is able to control or dispatch as adjustments to net internal demand, similar to DEP. Nonetheless, the Commission concludes that for the purposes of this proceeding, the reserve margins provided by the electric power suppliers are adequate, and that DEC, DEP, and DNCP should maintain their proposed reserve margins as filed.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The Regulatory Conditions in the Merger Order set forth commitments made by merging entities and their North Carolina public utility subsidiaries, DEC and PEC (now DEP), as a precondition of approval of the merger. As pointed out in the Public Staff's initial comments, a number of the conditions are relevant to this proceeding, but Regulatory Conditions 3.5 (Least Cost Integrated Resource Planning and Resource Adequacy), 3.6 (Priority of Service), and 4.1 are of particular significance. Regulatory Conditions 3.5 and 3.6 state as follows:

> 3.5 Least Cost Integrated Resource Planning and Resource Adequacy. DEC and PEC shall each retain the obligation to pursue least cost integrated resource planning for their respective Retail Native Load Customers and remain responsible for their own resource adequacy subject to Commission oversight in accordance with North Carolina law. DEC and PEC shall determine the appropriate self-built or purchased power resources to be used to provide future

[23] DEC and DEP verified responses at 15, 17.

[24] DEC and DEP verified responses at 16, 18.

generating capacity and energy to their respective Retail Native Load Customers, including the siting considered appropriate for such resources, on the basis of the benefits and costs of such siting and resources to those Retail Native Load Customers.

3.6 Priority of Service.

(a) The planning and joint dispatch of DEC's system generation and Purchased Power Resources shall ensure that DEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA [Joint Dispatch Agreement]. DEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

(b) The planning and joint dispatch of PEC's system generation and Purchase Power Resources shall ensure that PEC's Retail Native Load Customers receive the benefits of that generation and those resources, including priority of service, to meet their electricity needs consistent with the JDA. PEC shall continue to serve its Retail Native Load Customers with the lowest-cost power it can reasonably generate or obtain as Purchase Power Resources before making power available for sales to customers that are not entitled to the same level of priority as Retail Native Load Customers.

In addition, Regulatory Condition 4.1 provides that:

> DEC and PEC acknowledge that the Commission's approval of the merger and the transfer of dispatch control from PEC to DEC for purposes of implementing the JDA and any successor document is conditioned upon the JDA or successor document never being interpreted as providing for or requiring: (a) a single integrated electric system, (b) a single BAA [Balancing Authority Area], control area or transmission system, (c) joint planning or joint development of generation or transmission, (d) DEC or PEC to construct generation or transmission facilities for the benefit of the other, (e) the transfer of any rights to generation or transmission facilities from DEC or PEC to the other, or (f) any equalization of DEC's and PEC's production costs or rates. If, at any time, DEC, PEC or any other Affiliate learns that any of the foregoing interpretations are being considered, in whatever forum, they shall promptly notify and

consult with the Commission and the Public Staff regarding appropriate action.

In its comments, the Public Staff stated that the 2012 IRPs filed by DEC and DEP appear to comply with these requirements. The Commission agrees and concludes that, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP should continue to pursue least-cost integrated resource planning and file separate IRPs until required or allowed to do otherwise by Commission order or until a combination of the utilities is approved by the Commission.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-10

In the 2010 and 2011 IRP Orders, the Commission required the IOUs and the EMCs to include in their IRPs, among other things: (1) fuller discussions of their DSM/EE projections and programs, and (2) discussions of any year-to-year annual variance of 10% or more in their projected forecasts of DSM/EE resources. In its comments, the Public Staff indicated that the IOUs and EMCs have generally included these discussions in their IRPs, together with discussions of use of DSM/EE resources during system peak.

Over the planning horizon of the current IRP cycle, DEC projected capacity savings from DSM and EE that are generally 2% to 22% greater[25] than the projections in its 2011 IRP. Its energy savings in the 2012 IRP as compared to those in the 2011 IRP decrease in the early years by a combined 46%, but then increase by over 34%[26] by 2026 and beyond. DEC attributes these changes to the updating of its expectations for program performance, including new DSM and EE programs implemented in 2012 and the expectations identified in its 2012 market potential study. Calculations of projected participation and impacts were largely based on its most current five-year projection, with the five-year projection of impacts remaining constant after the fifth year through the end of the planning horizon. The figures do not include the impact of the grid modernization project discussed below.

Except for 2013, DEP's projected capacity savings from DSM and EE are generally 9% to 19.5% lower than the projections included in the 2011 IRP. However,

[25] Comparison of Line 17 of Table 8A in DEC's 2011 and 2012 IRPs.

[26] Year-by-year comparison of Table 4A in DEC's 2011 and 2012 IRPs. DEC changed the format of Table 4A in its 2012 IRP by adding a column showing the cumulative impacts of its EE programs. However, the Public Staff's calculations are based on a comparison of impacts added in 2011 versus those added in 2012, which do not include the cumulative impacts of the DSM/EE portfolio. The Public Staff believes it is more appropriate to reflect the cumulative impacts of DSM and EE programs as new measures are installed and old measures approach the end of their useful measure lives.

energy savings increase 4.2% to 19% over the same planning horizon.[27] DEP also developed its projections of DSM and EE based on the findings of its 2012 market potential study, and attributes the significant changes between the projections in its 2011 IRP and the 2012 IRP to the fact that its new market potential study was conducted by a different consultant who employed a different methodology that assumes a different relationship between MWh energy savings and peak MW demand savings. DEP cites this change in methodology as a driver for its forecasted increase for MWh energy savings and decrease for peak MW demand savings.

DNCP projected significantly lower MW and MWh savings from its portfolio of DSM and EE programs in its 2012 IRP than in its 2011 IRP, a 13% to 31% decrease in its forecast of capacity savings and a 23% to 72% decrease in energy savings over the planning horizon.[28] The larger percent decreases occur early in the planning horizon and appear to be due to regulatory changes in Virginia, as discussed more fully below. DNCP's practice of seeking approval of DSM and EE programs in Virginia before it seeks approval in North Carolina, and the cost caps imposed by the Virginia State Corporation Commission (VSCC), have hampered further development of its North Carolina DSM/EE portfolio. In its comments, the Public Staff stated that it is working with DNCP to determine whether it is cost-effective to offer the Commercial HVAC Upgrade and Commercial Lighting Programs on a North Carolina-only basis, and also to ascertain the proper jurisdictional allocation of the applicable costs. The Commission notes that this program received Commission approval on April 29, 2013, in Docket No. E-22, Sub 486.

In comparison with the capacity savings shown in its 2011 IRP, NCEMC's current projections[29] are generally greater in the earlier years of the planning horizon by as much as 36%, but show declines by as much as 12.7% in later years.[30] In response to a Public Staff data request, NCEMC indicated that the "Load Management and EE" data in Tables 1.3 and 1.4 of its IRP reflect EE program capacity savings at the time of the summer and winter coincident peaks. The Public Staff stated that it believes that these numbers actually reflect the DSM/EE program capacity available as a resource. However, the data also include customer-owned generation. The Public Staff stated in its comments that including both DSM/EE resources and customer-owned generation in Line 2 of Tables 1.3 and 1.4 makes it difficult to isolate only the DSM/EE program

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[27] Changes in capacity and energy savings of DSM and EE programs are based on a comparison of tables on pages E-8 and E-9 of Appendix E of DEP's 2011 IRP and page E-11 of Appendix E of DEP's 2012 IRP.

[28] Calculated based on a comparison of Appendix 2H and 5E of DNCP's 2011 and 2012 IRPs

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[29] For the participating EMCs, NCEMC prepared the 2012 IRP, including load, capacity savings, and energy savings forecasts, while GreenCo prepared the 2012 REPS compliance plan, which included descriptions of the DSM and EE programs incorporated into the forecast tables of NCEMC's 2012 IRP.

[30] Percent changes for capacity are based on a year-to-year comparison of Line 2 in Table 1.3 of the 2011 and 2012 IRPs, which also includes customer-owned generation.

capacity. The Public Staff recommended that in future IRPs, NCEMC include separate line items for projected capacity from its DSM/EE portfolio and from customer-owned generation.

NCEMC's projections in its 2012 IRP of energy savings from its DSM/EE portfolio, as compared with the corresponding projections in its 2011 IRP, are 6% to 16% greater in the early years of the planning horizon, but decrease 3% to 13% in the later years of the planning horizon.[31] NCEMC indicated that these fluctuations result from changes in the EnergyStar Lighting and EnergyStar New Homes programs. The Public Staff indicated that its review of Table 6.2 in NCEMC's 2012 IRP also found decreases in the energy savings of the Commercial Energy Efficiency program, while the other DSM/EE programs maintain consistent or slightly higher savings across the planning horizon. In combination, these changes significantly decrease the energy savings from the portfolio of DSM/EE programs over the planning horizon, in comparison with the 2011 IRP.

The Public Staff's review of the DSM/EE portions of the 2012 IRPs filed by the independent EMCs -- Haywood, Piedmont, Rutherford, and EnergyUnited -- indicates that there is little difference from those filed in previous IRPs.

Each of the electric power suppliers also provided a listing and description of its current and proposed DSM/EE programs. DEC's portfolio of DSM/EE programs in its 2012 IRP includes the programs contained in its 2011 IRP. In addition, DEC added a Tune and Seal measure to its Residential Smart Saver Program, which was approved in Docket No. E-7, Sub 831; My Home Energy Report, which was approved in Docket No. E-7, Sub 1015; Residential Neighbor Low Income Program, which was approved in Docket No. E-7, Sub 1004; Appliance Recycling Program, which was approved in Docket No. E-7, Sub 1005; and the Call Option 200 measure in the Power Share Call Option program, Docket No. E-7, Sub 953. DEC indicated that it was considering proposing the My Energy Manager Program, a residential energy management solution.

DEP's portfolio of DSM/EE programs includes the programs identified in its 2011 IRP. Additional programs in DEP's 2012 IRP are the Residential New Construction Program, approved in Docket No. E-2, Sub 1021, and the Small Business Energy Saver Program, approved in Docket No. E-2, Sub 1022. DEP modified its Residential Lighting Program (renamed Energy Efficiency Lighting) in Docket No. E-2, Sub 950, to expand the measures offered and the availability of the program to non-residential customers. DEP also received approval to modify the Residential Home Energy Improvement Program (Docket No. E-2, Sub 936) and discontinue offering its Residential Home Advantage Program (Docket No. E-2, Sub 928), both due to cost-effectiveness issues. DEP also discontinued its Solar Water Heating Pilot Program, originally approved April 21, 2009, in Docket No. E-2, Sub 937, in 2012 because the program was not cost-effective. In addition to these program changes, DEP also included in its DSM/EE

[31] Percent changes for energy savings are calculated from data in Tables 6.2 of the 2011 and 2012 IRPs.

portfolio its Prepay EE program, which is currently approved as a pilot program only in South Carolina.

DNCP's portfolio includes the same DSM and EE programs discussed in the 2011 IRP, with several notable exceptions. Recently, DNCP was denied regulatory approval by the VSCC to expand its Residential Lighting program and implement its new Commercial Refrigeration program. The Commercial Lighting and HVAC programs were also terminated in Virginia and ultimately suspended in North Carolina due to cost-effectiveness issues. However, DNCP gained approval in Virginia for its Commercial Distributed Generation DSM program, Commercial Duct Testing and Sealing program, and Residential Bundle program.[32] DNCP indicated that it intends to file the Commercial Duct Testing and Sealing and Residential Bundle programs in North Carolina later this year.[33]

DNCP included a list of DSM and EE programs being considered for implementation. The list of programs is largely consistent with the list of proposed programs identified in the 2011 IRP, and includes a resubmittal to the VSCC of the Commercial HVAC and Lighting programs previously denied approval.

The Public Staff stated in its comments that it has worked collaboratively with DEC, DEP, DNCP, and other interested parties to encourage continuation of existing and implementation of new cost-effective DSM/EE programs. The Public Staff commented that the regulatory environment in Virginia continues to challenge the expansion of DNCP's portfolio in North Carolina, and that the cost recovery mechanisms for DEC, DEP, and DNCP will all be reviewed in 2013 and 2014. These subsequent changes to the mechanisms will impact the development of future DSM/EE programs for the IOUs.

The Commission finds that the IOUs and EMCs have adequately discussed their DSM/EE programs in their 2012 IRPs.

Consumer Education Programs and Changes

Commission Rule 8-60(i)(6)(iv) requires each utility to provide a comprehensive list of all consumer education programs it currently provides to its customers, or proposes to implement within the biennium. The utility is also required to provide a list of any educational program it has discontinued since its last biennial report and the reasons for discontinuance.

In its comments, the Public Staff noted that DEC did not specifically address this requirement in its IRP. However, the Public Staff noted that a number of DEC's

[32] The Residential Bundle program provides several HVAC-related measures to tune existing HVAC systems or upgrade to more efficient HVAC systems.

[33] DNCP filed these programs on August 20, 2013, in Docket No. E-22, Subs 496 and 500.

programs provide customer education. The Public Staff recommended that DEC address this requirement in its reply comments.

In its reply comments, DEC indicated that it has not discontinued any consumer education programs since the last IRP and currently has no plans to implement a new program. DEC provided a list and description of its current consumer education programs, which include Smart Energy Now, Non-Residential Assessments, Duke Energy Online Customer Education Resources, My Home Energy Report, Online Energy Audit, Energy Calculators, Energy Savings Tips, Home Energy House Call, and the K-12 Energy Efficiency Programs.

DEP's list of consumer education programs and changes to those programs remains consistent with previous IRPs. DEP's main consumer education initiative continues to be its Customized Home Energy Reports.

The lists of consumer education programs discussed by DNCP, NCEMC, Piedmont, EnergyUnited, and Haywood remain largely unchanged from the lists provided in their 2011 IRPs.

The Commission finds that the IOUs and EMCs have adequately addressed their consumer education programs in their 2012 IRPs.

<u>Measures to Inform Customers of Forecasted Peaks and DSM Programs</u>

In its October 30, 2012 Order in Docket No. E-100, Sub 133, which post-dated the filing of the 2012 IRPs, the Commission encouraged electric utilities to take appropriate measures to inform all customers of their system summer peaks so that they might engage in voluntary demand response and peak shaving. In its initial comments in this proceeding, the Public Staff stated that it expected the IOUs and EMCs to include a discussion of their plans to provide customers with this information in their 2013 IRPs.

In their reply comments, DEC and DEP noted that they proactively provide voluntary programs through its Demand Response Programs department to both residential and commercial customers. In addition, they stated that during periods when peak customer usage and/or system conditions forecast the need for additional conservation measures, DEC and DEP have communication plans in place to notify state government agencies, the general public, and company facilities and employees to conserve energy.

DNCP stated in its reply comments that it utilizes several methods to inform its customers of upcoming system peaks in both the summer and winter, including targeted news releases, routine news releases encouraging conservation, promotion of voluntary energy conservation through the internet and social media, and through its media relations staff highlighting energy conservation during peak periods on television and radio interviews.

The Commission finds that the IOUs have included an adequate discussion of their measures to inform all customers of their system summer peaks in their 2012 IRPs.

<u>DSM/EE Market Potential Studies</u>

The 2011 IRP Order required IOUs to include in their IRPs a discussion of their market potential studies, including updates, for DSM and EE programs.

DEC briefly discussed its market potential study for DSM/EE programs completed in late 2011 and indicated that the results were incorporated into Tables 4.A and 4.B of its 2012 IRP. The market potential study indicates that additional potential for DSM and EE in DEC's North Carolina jurisdiction exists, both through new programs and existing programs.

DEP's market potential study is incorporated into its tables of costs and savings identified in Appendix E of its IRP. As in DEC's case, the market potential study suggests that additional potential exists to achieve savings through new DSM/EE programs and expansion of existing programs.

Both DEC's and DEP's market potential studies are based on an economic potential calculated using an avoided cost of $0.07 per kWh. The Public Staff noted in its comments that DEC's consultant (who was also DEP's consultant) stated that its use of this rate was based on its judgment of a reasonable avoided cost considering the hourly shape of EE load impacts and consistency with DEC's avoided cost embedded in DSMore™ and used in its approved DSM/EE cost recovery mechanism. The Public Staff stated that it was concerned that this cost may be too high to properly assess the economic potential of DSM and EE in the Carolinas, particularly based on filings by the IOUs in the current avoided cost proceeding[34] that suggest that underlying avoided costs used to support the avoided cost rates proposed by the IOUs have decreased in the last two years. DEC's and DEP's market potential studies also included an assessment of economic potential using an alternative avoided cost of $0.05/kWh, resulting in an economic potential approximately 30% and 28% less than that calculated using the avoided cost rate of $0.07/kWh, respectively. Even at $0.05/kWh, DEC and DEP continue to see 8,222 and 6,493 million kWh of economic potential, respectively.

In their initial and reply comments, Sierra Club and SACE commented that relying on the PURPA avoided cost rates, as suggested by the Public Staff, would result in an underestimation of the economic potential of DSM and EE programs. Instead, Sierra Club and SACE propose that DEC and DEP utilize the "real levelized system benefit" to estimate the benefits of its DSM/EE programs and measures. Using this method, Sierra Club and SACE calculated the real levelized benefit of EE/DSM of

[34] Docket No. E-100, Sub 136 - 2012 Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities.

$0.097 per kWh for DEC and $0.113 per kWh for DEP for the planning period (2012-2031). To further support their assertion that avoided costs developed for PURPA purposes underestimate the system benefit of EE, Sierra Club and SACE provided data from three other utilities that have utilized this approach in their 2011 IRP processes, including TVA, PacifiCorp, and Avista Utilities. Based on this analysis, Sierra Club and SACE concluded that "using the PURPA avoided cost to measure the benefit of energy efficiency skews the cost-effective analysis and undervalues the economic potential of the resource."[35] Sierra Club and SACE recommended that DEC and DEP

- Update their potential studies to reflect the real levelized benefit of EE/DSM, which would result in higher economic potential, and should also update their achievable potential estimates for energy efficiency based on this higher estimate.
- Develop a method for estimating the benefit of energy efficiency that is consistent with the system benefit as demonstrated in their resource planning revenue models.
- Using the real levelized benefit of EE/DSM to estimate avoided cost, DEC and PEC should review their current and planned energy efficiency programs, update the programs' cost-effectiveness calculations, and enhance the programs with additional cost-effective measures to achieve greater customer savings.[36]

In addition, in their initial comments Sierra Club and SACE noted the large number of industrial and large commercial customers that choose to "opt-out" of utility sponsored EE programs and associated riders by implementing alternative DSM and EE measures at their own expense pursuant to G.S. 62-133.9(f) results in a significant lost resource opportunity. Sierra Club and SACE recommended several steps to address the impacts of the opt-out provision, including: (1) DEC and DEP pursuing opportunities to offer programs to these sectors; (2) the Commission initiating a process to verify that opt-out customers are actually implementing their own measures; (3) commercial and industrial customers provide the utilities with better information on their EE efforts, and (4) developing cooperative approaches to increasing the attractiveness of DSM and EE programs to industrial customers.[37]

The Commission notes that the effect of the opt-out provision was raised in DEC's annual DSM/EE cost recovery proceeding in Docket No. E-7, Sub 1031, and in DEC's proposal for approval of a new DSM/EE mechanism in Docket No. E-7, Sub 1032. In the proposed order filed by the Public Staff and DEC on July 25, 2013, in Sub 1031, DEC and the Public Staff proposed that the Commission authorize DEC, the Public Staff, and other interested parties to discuss a potential study or survey of

[35] Sierra Club and SACE reply comments at 2.

[36] Id. At 8.

[37] Sierra Club and SACE initial comments at 36-37.

opted-out customers within the collaborative process and to file an update of these discussions as part of its 2014 DSM/EE rider filing and any formal proposal regarding an opt-out study if deemed feasible and appropriate.

In Request Nos. 6, 7, and 8 of its Order Requiring Verified Responses, the Commission asked DEC and DEP to comment on several studies assessing the economic potential of energy efficiency in North Carolina and the Southeast.[38] In their June 10, 2013, reply comments, DEC and DEP generally indicated that the reports did not represent a significant departure from the economic potential analysis utilized by DEC and DEP in their forecasts, and that the following reasons explained some of the different findings amongst the studies: 1) uncertainty regarding customer adoption rates; 2) the time horizons considered; and 3) consideration of potential efficiency gains from building codes, appliance standards, and the natural replacement of end-of-life equipment, all of which are largely captured in the load forecasts of the utilities' IRPs rather than in the EE forecast.

DNCP did not update its 2009 market potential study as part of this proceeding. In its comments, the Public Staff stated that DNCP indicated that it intends to update its market potential study in 2013 and will incorporate the new market potential study in its 2013 IRP. In its March 5, 2013, reply comments, DNCP confirmed this statement.

Both GreenCo and EnergyUnited provided the Public Staff with copies of their respective updated market potential studies, which were completed in late 2012. Their estimates of future achievable potential are consistent with findings from several other evaluators conducting studies across the country. However, neither market potential study considered DSM in its evaluation. Both market potential studies were based on achieving an overall 40% market penetration, which the Public Staff found to be aggressive goals for EnergyUnited and GreenCo's individual member EMCs, given the current adoption and participation rates for EE programs for EnergyUnited and some of the EMCs. The recommendations contained in the market potential studies indicate that even with a 20% market penetration level, additional market potential for EE is available by adding new measures to existing programs, adopting new EE programs, and particularly for GreenCo, encouraging member EMCs to implement some of the existing portfolio programs that they do not currently offer. Neither market potential study expressly discusses the avoided costs used to develop the achievable potential. While a brief discussion of national EE resources in both market potential studies suggests that EE is available at $0.03 per lifetime kWh saved, the studies do not address the North Carolina achievable potential of cost effective EE.

[38] The three studies were the January 2013 report by the Georgia Institute for Technology, in cooperation with Oak Ridge National Laboratory entitled "Estimating the Energy-Efficiency Potential in the Eastern Interconnection", the 2006 GDS Associated report entitled "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina," and the March 2010 report by the American Council for an Energy Efficient Economy entitled "North Carolina's Energy Future: Electricity, Transportation, and Water Efficiency."

Piedmont, Haywood, EnergyUnited, and Rutherford did not include a discussion of a market potential study in their IRPs.

The Commission finds that the IOUs have included an adequate discussion of their market potential studies, including updates, for DSM and EE programs in their 2012 IRPs.

Use of DSM for Possible Fuel Savings

The 2011 IRP Order required each IOU and EMC to investigate the value of using DSM resources during times of high system load, when the marginal cost of fuel is generally at its highest, as a means of achieving lower fuel costs.

DEC discussed its use of DSM resources at various times to respond to both economic and reliability conditions on its system. DEC used some of these occasions to study the potential for fuel cost savings at times of high system costs, focusing on its Power Manager program. DEC's calculations indicate that potential fuel cost savings from this program were quite small and that the benefit of fuel savings is far outweighed by the avoided capacity costs. Through the use of both participant and non-participant surveys related to DSM usage, DEC concluded that customers could tolerate more frequent, but shorter-duration interruption events without causing participants to leave the DSM program. However, customer participation dropped significantly with longer duration DSM activations. DEC concluded that without careful management, using the DSM program to achieve fuel savings may result in customer attrition.

DEP performed a similar analysis on its Energy Wise Air Conditioning Load Control DSM program. Using actual historical Energy Wise events over the 2009 to 2011 period, DEP estimated that approximately $53,000 in fuel savings was achieved. However, the reduction in participation in Energy Wise would result in a net savings decrease of $49,000. DEP estimated that a net fuel savings of approximately $91,000 to $207,000 could be achieved over the next three years. Like DEC, DEP also evaluated customers' tolerance of more frequent DSM events, using survey and feedback data from current Energy Wise participants. DEP concluded that activating Energy Wise for economic purposes appeared to provide little or no additional value, when balanced with the risks associated with customer acceptance and retention.

DNCP did not expressly address the use of DSM to achieve fuel savings in its IRP. The Public Staff noted that in response to data requests, DNCP indicated that it had not undertaken any formal study of the effects of greater use of DSM during high system load conditions to achieve fuel savings, but acknowledged that it was reasonable to assume that fuel savings result from the use of demand response resources. DNCP included a brief discussion regarding the negative effect on participation in its Residential Air Conditioning Cycling DSM after activations over multiple days during the summer of 2011. As a result, DNCP observed some negative customer feedback, which resulted in customers leaving the program.

NCEMC and the three of the other EMCs indicated that their evaluation of possible fuel savings from the use of DSM resources suggested that at no time during the year were the marginal energy costs greater than the marginal costs associated with activating DSM resources. As a result, NCEMC indicated there were no potential fuel savings to be gained.

In its comments, the Public Staff noted that the potential benefits of using DSM for fuel savings were not as large as it had originally theorized. Based on the findings by DEC and DEP, and DNCP's first-hand experience with customer pushback, the Public Staff recommended that DNCP not be required to conduct a study of potential fuel savings from DSM. In its reply comments, DNCP agreed with the Public Staff's recommendation. The Public Staff stated that it did not believe it was necessary to continue to require discussion of this issue in future IRPs. In their reply comments, Sierra Club and SACE agreed with the Public Staff's recommendation as to current DSM programs, but stated that "utilities should have the opportunity to propose pilot programs or offer new technologies for using DSM to achieve economic fuel savings in the future."[39]

The Commission agrees with the Public Staff that the electric power suppliers should not be required to investigate this issue further. However, electric power suppliers are encouraged to continue to consider potential fuel savings benefits in their evaluations of cost-effective DSM programs in the future.

Smart Grid Impacts and Plans

On April 11, 2012, the Commission issued an Order in Docket No. E-100, Sub 126, amending Commission Rule R8-60 and adopting Rule R8-60.1. Amended Rule R8-60 requires electric power suppliers to file information in their IRPs regarding the impacts of smart grid. Beginning with the 2012 IRP, electric power suppliers were to include specific information regarding their smart grid impacts, including a description of the technologies already installed or planned to be installed in the next five years, a comparison of the gross MW and MWh impacts, and impacts to the North Carolina retail jurisdiction and customer classes. Beginning with the 2013 IRP, Rule R8-60.1 requires the electric power suppliers to include a "Smart Grid Technology Plan" with specific information regarding future investments in smart grid technologies.

DEC provided a general description of its "Grid Modernization" program, which involves improvements to its distribution system. DEC estimates that this effort will result in an additional 40 to 135 MW of reduced load over a 10-year period. As a result, DEC included 135 MW of smart grid impacts in the "DSM" column in Table 1.A of its IRP. DEC did not include any discussion of these impacts to the North Carolina retail jurisdiction or customer classes.

[39] Sierra Club and SACE reply comments at 8.

DEP provided a discussion of its Distribution System Demand Response (DSDR) program, which involves feeder conditioning, monitoring, and two-way communication capabilities. DEP completed installation of the DSDR program in 2012, and is continuing testing into the 2013 summer season. Ultimately, DEP estimates that DSDR will provide approximately 236 MW of DSM capacity. In its comments, the Public Staff stated that in response to a data request, DEP indicated that once DSDR is fully operational, DEP will incorporate the impacts now associated with its legacy voltage control demand response program and will discontinue reporting voltage control savings separately from DSDR. DEP segregated the impacts of DSDR for the North Carolina retail jurisdiction and customer classes in its IRP.

The Public Staff noted that DNCP did not specifically address its smart grid impacts or discuss plans for smart grid deployment in its 2012 IRP, but included in Chapters 3 and 7 of its 2012 IRP a brief discussion of its advanced metering infrastructure (AMI) and its dynamic pricing pilots that are under way in its Virginia service territory. The Public Staff recommended that DNCP include a discussion of its current smart grid impacts, including impacts by jurisdiction and customer classes, in its reply comments.

In its reply comments, DNCP provided additional details regarding the effectiveness and benefits of installing AMI or smart meters on homes and businesses in several demonstration areas across Virginia. The AMI demonstrations test the effectiveness of its Voltage Conservation program, remotely turning off and on electric service, and Dynamic Pricing Program, both of which are enabled by leveraging AMI as the foundational smart grid technology. DNCP estimated that the Voltage Conservation program saved an estimated 25,773 MWh in demonstration areas across Virginia in 2012, and that approximately 1,317 MWh should be applied to its North Carolina jurisdictional allocation. With regard to the Dynamic Pricing program, DNCP indicated that in response to data requests, it provided the Public Staff with an initial report that included information on customer enrollment and education, but "due to the nature of the rates, a full year of participation is required to analyze energy and demand savings."[40] DNCP stated that an initial measurement and verification (M&V) study will be provided as part of its 2013 annual report to be filed in August 2013, including information on energy and demand savings for the pilot period.

DNCP also noted in its reply comments that the current filing requirement for Smart Grid Technology Plans, July 1 of each odd-numbered year, does not coincide with the filing date of September 1 of each even-numbered year for IRPs, and that the inconsistency in the timing of these two requirements is not ideal for the utilities to develop and utilize the most current IRP analysis in their development of Smart Grid Technology Plans. DNCP therefore indicated that it would seek to coordinate with other utilities and the Public Staff regarding a delay, either of by motion or rule, of this requirement to October 1, 2014, and every two years thereafter, in order to synchronize the Smart Grid Technology Plan with the IRP filing requirements. In their reply

[40] DNCP reply comments at 8.

comments, DEC and DEP indicated that they support this recommendation. DNCP moved to amend Rule R8-60.1 on April 10, 2013, in Docket No. E-100, Sub 126, to change the filing date to October 1, 2014. The Commission granted the motion on May 6, 2013.

NCEMC provided a brief discussion of its grid modernization program, including deployment of a new demand response platform known as “Control Data Settlement System” (CDSS), which will support the AMI that several EMCs are implementing. The new CDSS will incorporate two-way communication capabilities and is intended to provide additional opportunities for DSM. NCEMC indicates that the first such program will be its customer-owned generation program. NCEMC also included information regarding the projected impacts of its smart grid initiatives by jurisdiction and customer classes.

Rutherford, Piedmont, Haywood, and EnergyUnited did not include a discussion of smart grid impacts or plans in their respective IRPs. The Public Staff recommended that Rutherford, Piedmont, Haywood, and EnergyUnited include a discussion of its smart grid plans in their reply comments. Rutherford and EnergyUnited filed reply comments addressing their smart grid plans.

The Commission finds that the discussions regarding the impacts of smart grid deployment are adequate for purposes of the 2012 IRPs.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

Assessment of Alternative Supply-Side Energy Resources

Commission Rule R8-60(i)(7) requires each utility to file its current overall assessment of existing and potential alternative supply-side energy resources, including a descriptive summary of each analysis performed or used by the utility in the assessment. Each utility must also provide general information on any changes to the methods and assumptions used in the assessment since its most recent biennial or annual report.

For the currently operational or potential future alternative supply-side energy resources included in each utility's plan, the utility must provide information on the capacity and energy actually available or projected to be available, as applicable, from the resource. The utility must also provide this information for any actual or potential alternative supply-side energy resources that have been discontinued from its plan since its last biennial report and the reasons for that discontinuance. For alternative supply-side energy resources evaluated but rejected, the utility must provide the following information for each resource considered: a description of the resource; the potential capacity and energy associated with the resource; and the reasons for the rejection of the resource. Each utility provided the information required by Commission Rule R8-60(i)(7).

Based on its planning assumptions, DEC projects that approximately 970 MW of renewable energy resources will be interconnected to its system by 2021, growing to approximately 1,665 MW by 2032. This is a significant increase from DEC's projections in 2011, which estimated approximately 686 MW in 2021 and 884 MW in 2031. Even more striking is the change by renewable energy resource type, which shows an increase in solar by an order of magnitude. In DEC's 2011 IRP, it forecast 51 MW of additional solar capacity by 2021 and 82 MW by 2031. In the current IRP, DEC forecasts 538 MW of new solar capacity by 2021 and 1004 MW by 2032. Further, DEC forecasts a significant decrease in the capacity additions from biomass, reducing its 2011 estimates of 295 MW in 2021 and 391 MW in 2031 to 108 MW in 2021 and 173 MW in 2032. The Public Staff noted that this change in DEC's forecast is consistent with the number of reports of proposed construction and applications for certificates of public convenience and necessity (CPCNs) filed by small power producers, particularly for proposed utility-scale solar PV facilities.

DEP did not provide as detailed a breakdown of its available or projected alternative supply-side energy resources, but did indicate that it forecasts purchasing 208 MW from renewable QFs in 2021 and 210 MW from renewable QFs in 2027. These numbers are an increase from DEP's 2011 IRP, in which it forecast 176 MW in 2021 and 39 MW in 2026.

DNCP projects that it will have 166 MW of renewable capacity in 2013, and that by 2027, it will add 248 MW of onshore wind resources and 34 MW of solar resources, convert three coal-fired facilities (totaling approximately 151 MW) to utilize biomass resources, and purchase additional biomass resources.

NCEMC listed three solar facilities totaling 6.8 MW AC and one landfill gas facility with a capacity of approximately 1 MW as currently operational or potential future alternative supply-side energy resources. It stated that it continues to be engaged in discussions with several developers of additional alternative supply-side resources.

In its comments, the Public Staff commended DEC on its analysis and discussion of alternative supply-side resource additions, as well as its clear delineation of new capacity additions by resource type. The Public Staff also recommended that in their future IRP filings, the other utilities provide additional details and discussion of projected alternative supply-side resources in a manner similar to that utilized by DEC.

In its reply comments, DNCP indicated that it believed its discussion of alternative supply-side resource additions met or exceeded the level of information and analysis provided by DEC, and therefore meets the Public Staff's recommendation.

Over the past few years, the landscape of alternative and distributed resource options has undergone considerable changes, as reflected in part by in the volume and scale of projects seeking CPCNs from the Commission. Greater analysis by the utilities on how these resources will integrate into their system, as well as any costs or benefits associated with the new resources, should be more fully considered in future IRPs. The

Commission agrees with the Public Staff that DEC's discussion of recent developments of alternative supply-side resources is a good starting point, and that utilities should continue to provide greater details of these developments in future IRP fillings.

In its amended initial comments filed on February 7, 2013, MAREC indicated that it had concerns about the treatment of renewables, specifically wind, by DEC and DEP in the IRPs, and that several policy reasons supported further consideration of wind energy by the IOUs, including long-term price certainty, in-state investment and economic development, and environmental benefits. MAREC further proposed that DEC and DEP conduct a "new RFP process that would solicit at least 100 MW of new wind energy capacity through a long-term contract(s) for energy and RECs, which would act as a hedge against price volatility and help towards meeting their present and future REPS requirements."[41]

In their initial and reply comments, Sierra Club and SACE agreed that DEC's IRP reflected a more robust evaluation of renewable energy options than DEP's, but stated that both were still flawed in that they only evaluated higher levels of renewable energy resources at the initial screening phase. Sierra Club and SACE recommended that DEC and DEP, similar to DNCP, evaluate one or more "high renewables" portfolios that incorporate renewable energy resources above minimum REPS compliance. Sierra Club and SACE also agreed with MAREC that wind energy offers several benefits, including "lower production costs (and zero fuel costs), a smaller environmental footprint, and a modular nature that matches load growth more closely than larger capacity additions. They also recommended that DEC and DEP "evaluate wind energy not only for REPS compliance, but as a system resource."[42]

The Commission agrees with MAREC that DEP and DEC should continue to assess alternative supply-side resources such as wind energy on an ongoing basis. However, the Commission declines to recommend that the utilities conduct an RFP that is limited to a single resource type unless the specific resource is required for REPS compliance. The Commission does, however, agree that in future IRPs DEC and DEP should more fully consider resource scenarios that envision larger amounts of renewable energy resources similar to DNCP's Renewable Plan in their least-cost integrated resource planning, and to the extent those scenarios are not selected, provide a discussion regarding the reasons.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-14

Evaluation of Resource Options

DEC, DEP, and DNCP provided information regarding their analysis and evaluation of resource options as required by Rule R8-60(i)(8). The IOUs indicated that

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[41] MAREC amended initial comments at 9-10.

[42] Sierra Club and SACE reply comments at 12-13.

they use accepted production cost simulation models that identify the least cost mix of resources required to meet the future energy and capacity needs in an efficient and reliable manner at the least cost. These models have the ability to perform optimization analyses to select among competing resources that could be added in various combinations to satisfy the utility's future load requirements. They are designed to compare various generation portfolios to determine which has the lowest present value of revenue requirements (PVRR), while maintaining the target reserve margin, and is thus the least-cost portfolio.

The models incorporate forecasts of energy sales and peak load with planning assumptions on the operating characteristics of existing generating units (including, but not limited to net MW output, planned outages, forced outage rates, projected fuel prices, heat rates, start costs, emission costs, and variable operating and maintenance expenses) to calculate the projected dispatch cost of each generating unit. In order to arrive at a least cost plan, the models integrate assumptions regarding planned generation uprates and retirements, planned renewable energy generation, DSM and EE programs, environmental regulations, and the capital costs and operating characteristics for proposed traditional generation and alternative resources.

To consider the uncertainties, the utilities generally develop a base or preferred plan and alternative plans. These plans are analyzed under a variety of scenarios, including changes in projected loads, fuel prices, carbon dioxide (CO_2) emission credit prices, construction costs, and other sensitivities over the planning period, allowing the utility to choose the optimal plan that provides a balanced mix of traditional generation, renewable energy, DSM and EE to meet its baseload, intermediate, and peaking requirements.

In its comments, the Public Staff indicated that it reviewed the forecasts of fuel prices, existing generation characteristics, and the projected capital costs associated with new generation facilities used in the resource optimization models. The Public Staff indicated that based on its investigation, the projected operating and capital costs used in the production models, as well as the evaluation of resource options, were reasonable for purposes of this proceeding.

DEC's evaluation indicated that its preferred plan is the portfolio based on full ownership of two nuclear units going into service in 2022 and 2024, supplemented by combustion turbine (CT) and combined cycle (CC) natural gas-fired units. In its comments, the Public Staff noted that the all natural gas portfolio considered by DEC indicated a $10 million lower revenue requirement than the preferred nuclear portfolio. DEC maintained that the portfolios with nuclear remain competitive with the natural gas portfolio because the gas portfolio has more upside risk in fuel costs as identified in its sensitivity analysis. The Public Staff noted that DEC's contention that the nuclear portfolios are competitive is, in part, dependent on the assumption of a carbon constrained economy with the pricing of carbon under various cap and trade proposals or the enactment of clean energy legislation and DEC's desire to lower its carbon footprint. If carbon legislation is not enacted during the planning period, then the natural gas portfolio has a lower revenue requirement that is $3.8 billion lower than the nuclear portfolio and $3.5 billion lower than the regional nuclear portfolio.

In its comments, the Public Staff repeated the concerns regarding DEC's heavy reliance on nuclear generation it had previously raised in Docket No. E-7, Sub 819, and stated that "the benefit of additional nuclear generation from a fuel diversity perspective requires further evaluation. The economics of fuel diversity are difficult to quantify, especially during uncertain times. In addition, the potential risks associated with added construction costs and other uncertainties associated with nuclear power raise additional questions on the merits of DEC's preferred plan."[43]

In their initial comments and reply comments, the Sierra Club and SACE agreed with the Public Staff, finding that further development of new nuclear generation is subject to numerous risks and uncertainties "weighing strongly against over-reliance on nuclear generation in the DEC and [DEP] IRPs."[44] Sierra Club and SACE contrasted the approach taken by DEC and DEP with TVA, which "evaluated the environmental impacts of each alternative resource portfolio in terms of air emissions, water impacts, and waste disposal costs (coal ash and nuclear) in its 2011 IRP." Sierra Club and SACE asserted that adopting a broader approach, similar to that used by TVA, would allow DEC and DEP to be more explicit about how to balance various environmental risks. Sierra Club and SACE also recommended that the uncertain costs associated with the handling and storage of nuclear waste be both discussed and quantitatively assessed in the utilities' resource evaluations.

Sierra Club and SACE also noted in their initial comments the large number of coal-fired units that DEC and DEP have retired or are scheduled to retire in the next few years due to more stringent environmental regulations that apply to coal-fired units. Similar to the argument they made in the 2010 IRP proceeding, Sierra Club and SACE noted that these regulations also pose risks to the utilities' remaining facilities, including those that are already equipped with emissions controls such as scrubbers. Sierra Club and SACE recommended that the electric power suppliers include in their IRPs a more detailed discussion of regulatory risks faced by their coal fleet, including scrubbed plants, and impending regulations, including information on any investments required in further pollution control equipment or increased operating expenses.

DNCP evaluated the following four generation portfolios: Plan A or its Base Plan, which consists of all natural gas facilities; Plan B or its Fuel Diversity Plan, which consists of a combination of new natural gas-fired CTs, CCs, 248 MW of onshore wind, 10 MW of solar, and a new nuclear unit located at the North Anna site; Plan C or its Renewable Plan, which includes 100 MW of generic biomass, 248 MW of onshore wind, 1,600 MW of offshore wind, 20 MW of solar, and a combination of new natural gas-fired CTs and CCs; and Plan D or its Coal Plan, which includes the development of two

[43] Public Staff initial comments at 58-59.

[44] Sierra Club and SACE reply comments at 11.

695-MW coal-fired facilities equipped with carbon capture and sequestration technology, along with a combination of new natural gas-fired CTs and CCs. Following its evaluation, DNCP selected its Plan B, Fuel Diversity, as its preferred plan, despite the fact that Fuel Diversity Plan, under current planning assumptions, produces a higher cost than its Base Plan.

In its comments, the Public Staff noted that the concerns it expressed about the risks of relying on nuclear generation in DEC's plan also apply to DNCP. The Public Staff recommended that an electric utility that selects a preferred plan based on fuel diversity elaborate and provide additional support for its decision in its reply comments. The Pubic Staff also stated that:

> The electric utility industry has experienced significant changes in recent years and will continue to face a great deal of uncertainty. Each of the utilities discussed in its IRP the evolving commodity and technology trends that have resulted in substantial changes in the landscape. Hydraulic fracturing and the production of shale gas have pushed down natural gas prices and may transform the energy market for decades to come. The environmental and regulatory risks of shale gas production, however, remain uncertain. In addition, other changes, such as smart grid technologies and generation using renewable energy resources, present new challenges and opportunities as they continue to develop. Finally, regulations at both the state and federal levels have the potential to substantially change a utility's preferred resource mix. [45]

In addition, the Public Staff recommended that to the extent a utility selects a preferred plan based on circumstances that may exist beyond the planning period the utility should provide a justification for its reliance or consideration of those circumstances.

In its reply comments, DNCP noted that in addition to the expiration of the operating licenses for two of DNCP's four nuclear units during the study period (Surry Units 1 and 2), two additional units (North Anna Units 1 and 2) have license expirations that occur shortly after the study period. DNCP stated that '[n]uclear plant operating licenses have a known finite life, and recognition of the expiration of these major generating facilities' operating licenses is a reasonable consideration for DNCP to use in evaluating its choice of the preferred plan." DNCP acknowledged that its preferred plan under current planning assumptions is a higher cost than the base plan, but DNCP maintains that "the Preferred Plan will provide fuel-price stability for customers over the long-term by reducing an over-reliance on any one fuel source (namely, gas) and/or generation technology at the lowest reasonable cost." DNCP stated that its current customers are benefitting substantially from the Company's historic investments in nuclear, and that the Preferred Plan does include the addition of 3,550 MW of new natural gas capacity, as well as additional nuclear, wind, and solar resources. In

[45] Public Staff initial comments at 61-62.

response to the Public Staff's recommendation, DNCP indicated that it will develop additional support should it determine that a fuel diversity plan is the preferred plan over the Base Plan in its next North Carolina IRP.

The Commission recognizes that diversity in a utility's resource mix may help to protect the utility and its customers from fuel price fluctuations, fuel unavailability, and regulatory uncertainties, and may also ensure stability and reliability in the State's electricity supply. Fuel diversification, however, must be justified by an analysis of the benefits and costs of alternatives to achieve the same objectives. DEC's IRP indicates that the benefits of fuel diversity associated with a new nuclear facility may come at an additional cost of $3.5 billion to $3.8 billion under certain scenarios. Similarly, DNCP's reply comments and the Public Staff's comments recognize the higher cost associated with the benefits of fuel diversity with nuclear generation over the Company's Base Plan. The Commission agrees that the potential benefits of fuel diversification warrant further consideration, and concurs with the Public Staff that to the extent an IOU selects a preferred resource plan based on fuel diversity, the IOU should elaborate and provide additional support for how its decision complies with the statutory requirement of least-cost planning.

<u>Concerns Raised by NC WARN, et al.</u>

In their initial comments, NC WARN, <u>et al.</u>, also expressed their opinions and concerns over several aspects of DEC and DEP's IRPs, including the following:

1) Expenditures on power plant construction that divert resources that could otherwise be utilized for weatherization and EE projects.
2) The much higher percentage of electricity that could be sourced from EE and renewable resources.
3) The IRPs do not reflect the economic potential for renewable energy resources and do not consider the potential of customer co-generation or combined heat and power (CHP).
4) The timing and escalating costs of nuclear plant construction pose significant economic risks to ratepayers, and the continued use of fossil fuels also raises significant environmental costs.

To support their positions, NC WARN, <u>et al.</u>, attached two reports. The first, a Greenpeace report entitled, "Charting the Correction Course: A Clean Energy Pathway for Duke Energy," utilized some of the same modeling tools used by DEC and PEC, with different assumptions. Based on the Greenpeace Plan, NC WARN, <u>et al.</u>, indicated that the overall costs of DEC and DEP's IRPs would decrease, while at the same time emissions would also be significantly reduced.

In their reply comments, DEC and DEP challenged the assumptions and methodology underlying the proposals submitted by NC WARN, <u>et al.</u>, stating that the proposals are not realistic if "North Carolina wants to ensure reliable and affordable electricity are available to residential, commercial, and industrial customers, as the Companies are obligated to do."[46] Further, DEC and DEP asserted that their IRPs present a robust and balanced portfolio that will cost-effectively and reliably serve customer's short and long-term needs across a range of possible future scenarios.[47]

The Commission recognizes the efforts of Greenpeace and others to develop alternative models and IRPs that test the inputs and assumptions that go into utility resource planning, but concludes that the plans proposed by the utilities are reasonable for planning purposes.

DISCUSSION AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15-16

In its March 21, 2007, Order Granting Certificate of Public Convenience and Necessity with Conditions for Cliffside Unit 6, in Docket No. E-7, Sub 790, the Commission ordered DEC to retire, in addition to Cliffside Units 1-4, "older coal-fired generating units . . . on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from [new EE and DSM] programs, up to the MW level added by" Cliffside Unit 6, i.e., 825 MW.[48] In the air permit issued by the North Carolina Department of Environment and Natural Resources, Division of Air Quality (DAQ) for Cliffside Unit 6, DAQ required DEC to implement a Greenhouse Gas Reduction Plan and to retire 800 MW of additional coal capacity without regard to achieving a commensurate level of MW savings from new EE and DSM programs. DEC's Greenhouse Gas Reduction Plan can be revised with DAQ's approval if the Commission determines that the scheduled retirement of any unit will have a material impact on the reliability of DEC's system.

In its 2011 and 2012 IRPs, DEC has included as Appendix J a Cliffside Unit 6 Carbon Neutrality Plan. This Plan incorporates actions required under the Greenhouse Gas Reduction Plan, as well as those required under DEC's additional obligations related to its Cliffside Unit 6 air permit to: (a) retire 800 MW of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, (b) accommodate to the extent practicable the installation and operations of future carbon control technology at Cliffside Unit 6, and (c) take additional actions as necessary to make Cliffside Unit 6 carbon neutral by 2018. Table J.1 indicates that DEC plans to cumulatively retire 1,299 MW of coal capacity, not including Cliffside Units 1-4, by the end of 2015.[49] The projected retirements under the Cliffside Unit 6 Carbon Neutrality Plan would exceed the requirements of the Greenhouse Gas Reduction Plan by close to 70%. DEC states

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[46] DEC and DEP reply comments at 11.

[47] Id.

[48] Order Granting Certificate of Public Convenience and Necessity with Conditions for Cliffside Unit 6, On March 21, 2007, in Docket No. E-7, Sub 790, at 140.

[49] On February 1, 2013, DEC announced the closure of Riverbend Units 4-7 and Buck Units 5 and 6 in April 2013. These units were listed in Table J.1 as closing by 2015.

that some older coal-fired units that are currently planned for retirement might instead be converted to natural gas. However, DEC will still greatly exceed the requirements of the Greenhouse Gas Reduction Plan, even with the possible coal-to-gas conversions.

Consistent with the 2011 IRP Order, the Public Staff recommended that the Commission approve the Cliffside Unit 6 Carbon Neutrality Plan as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit, but state that it is not approving any individual specific activities or expenditures for any activities shown in the Plan. The Public Staff recommended that DEC continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

The Commission agrees with the Public Staff's recommendation. Therefore, the Commission concludes that the Cliffside Unit 6 Carbon Neutrality Plan is a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; however, the Commission notes that this conclusion does not constitute approval of any individual specific activities or expenditures for any activities shown in the Plan.

DISCUSSION AND CONCLUSIONS FOR FINDING OF FACT NO. 17

2012 REPS COMPLIANCE PLANS

All of the electric power suppliers in this proceeding indicated that they will achieve the general and solar requirements in G.S. 62-133.8(b), (c), and (d) for the planning period. They also indicated that their expenses to comply with the REPS in the planning period would not exceed the annual cost caps established in G.S. 62-133.8(h)(3) and (4).

In its REPS compliance plan, DEC stated that because of uncertainty with environmental permit requirements, it has reduced its reliance on biomass for future REPS compliance. DEC noted that it will continue to pursue wind energy, either through REC-only purchases or through energy delivered to its customers in North Carolina to meet the in-state general requirement. However, the Commission notes that continuation of the federal production tax credit is uncertain, and repeal of the credit could limit future wind projects.[50]

DEP's REPS compliance plan indicated that it had implemented its Commercial and Residential SunSense programs to help it comply with the solar set-aside

[50] Section 407 of the American Taxpayer Relief Act of 2012 (P.L. 112-240, enacted on January 2, 2013) modified the eligibility criteria for the federal production tax credit for energy produced from qualifying renewable energy resources, including wind, by: (1) removing "placed in service" deadlines and replacing them with deadlines that use the beginning of construction as a basis for determining facility eligibility; and (2) extending the deadline for wind energy facilities by one year, from December 31, 2012, to December 31, 2013.

requirement of G.S. 62-133.8(d). The Residential SunSense program, which incentivizes solar PV systems up to 10 kW, was modified in February 2013 to reduce the up-front rebate paid to participants from $1 per watt to $0.50 per watt.

Halifax plans to meet the general REPS requirements for itself and the Town of Enfield through its EE programs, SEPA allocations, and out-of-state wind RECs. In its comments, the Public Staff noted that Halifax did not provide an M&V plan as required in R8-67(b)(1)(iii), and recommended that it file an M&V plan with its next REPS compliance plan.

In its reply comments filed on March 5, 2013, Halifax provided additional details regarding its means of verification for each of its programs, but stated that "given its numbers of members and limited staff any additional requirements for measurement and verification of these programs would not be a cost-effective use of Cooperative resources."[51] Halifax requested that the Commission accept the measures utilized by Halifax as sufficient for each of the EE programs. As the Commission discussed in its May 14, 2012, Order in Docket No. E-100, Sub 113, the Commission recognizes that electric power suppliers that have small customer bases also have low REPS cost caps, and that rigorous M&V protocols may be inappropriate in some cases, with the cost quickly dwarfing the economic value of the energy savings being measured. The Commission notes that Halifax submitted with its 2013 REPS compliance plan (Docket No. E-100, Sub 139) worksheets demonstrating how it calculated the energy savings for each of its EE programs. The Commission finds the level of data provided by Halifax in its 2013 submittal to be appropriate.

Swine and Poultry Waste Set-Asides in G.S. 62-133.8(e) and (f)

Several electric power suppliers indicated in their 2011 REPS compliance plans that they have had difficulty in obtaining RECs to comply with the swine and poultry waste set-asides in G.S. 62-133.8(e) and (f), which require them to meet a portion of their REPS obligations with energy derived from swine waste and poultry waste beginning in 2012. On May 16, 2012, the Commission issued an Order in Docket No. E-100, Sub 113, requiring the electric power suppliers to file an update on their efforts in meeting these compliance requirements. On June 1, 2012, the electric power suppliers filed a Joint Motion seeking to delay the swine and poultry waste set-asides as allowed in G.S. 62-133.8(i)(2). The joint movants claimed that they have had difficulty acquiring RECs to meet the swine and poultry waste set-asides because the technology for waste-to-energy facilities is still in its infancy and will need more time to reach maturity. A number of parties intervened in the docket, including three developers of waste-to-energy facilities, who indicated that they had had difficulty negotiating contracts with some of the electric power suppliers because of the lack of a standard contract form and lack of information on terms and conditions.

[51] Halifax reply comments at 2.

On November 29, 2012, the Commission issued an Order eliminating the 2012 swine waste set-aside requirement, delaying by one year the poultry waste set-aside requirement, requiring DEC and DEP to file triennial reports describing the state of their compliance with the set-asides and their negotiations with the developers of swine and poultry waste-to-energy projects, and requiring internet-available information to assist the developers of swine and poultry waste-to-energy projects in getting contract approval and interconnecting facilities.

In its comments, the Public Staff stated that it believes the electric power suppliers will likely continue to have difficulty meeting the swine and poultry waste set-asides even with a one-year delay. The Public Staff concluded that while all electric power suppliers are on course to meet the general and solar REPS requirements for the planning period, they will have difficulty meeting the Commission's revised swine waste and poultry waste requirements in 2013 and possibly 2014, though they are actively seeking energy and RECs to meet these requirements. In addition, the Public Staff noted that the EMCs and municipalities have submitted REPS compliance plans that satisfy most or all of the filing requirements of Commission Rule R8-67(b). According to the Public Staff, the compliance plans also indicate that the electric power suppliers should be able to meet their REPS obligations during the planning period without nearing or exceeding their cost caps.

The Commission agrees that, with the exception of the swine and poultry waste set-asides, the 2012 REPS compliance plans submitted by the electric power suppliers indicate that they are generally well-positioned to comply with their future REPS obligations. The Commission therefore concludes that the 2012 REPS compliance plans filed in this proceeding by the electric power suppliers are satisfactory and should be approved. The Commission notes that on September 16, 2013, most of the electric power suppliers filed a joint motion requesting to be relieved of their 2013 swine and poultry waste obligations. On September 23, 2013, the Commission issued an Order in Docket No. E-100, Sub 113, scheduling an evidentiary hearing regarding the joint motion.

IT IS, THEREFORE, ORDERED as follows:

1. That this Order shall be adopted as part of the Commission's current analysis and plan for the expansion of facilities to meet future requirements for electricity for North Carolina pursuant to G.S. 62-110.1(c).

2. That the IOUs' 15-year forecasts of native load requirements and other system capacity or firm energy obligations, supply-side and demand-side resources expected to satisfy those loads, and reserve margins are reasonable and are hereby approved.

3. That the 2012 biennial IRP reports filed in this proceeding by the IOUs, NCEMC, Piedmont, Rutherford, EnergyUnited, and Haywood are hereby approved.

4. That the 2012 REPS compliance plans filed in this proceeding by the IOUs, GreenCo, Halifax, and EnergyUnited are hereby approved.

5. That future IRP filings by all IOUs shall continue to include a detailed explanation of the basis and justification for the appropriateness of the level of the respective utility's projected reserve margins.

6. That future IRP filings by all IOUs shall continue to include a copy of the most recently completed FERC Form 715, including all attachments and exhibits.

7. That future IRP filings by all IOUs shall continue to: (1) provide the amount of load and projected load growth for each wholesale customer under contract on a year-by-year basis through the terms of the current contract, segregate actual and projected growth rates of retail and wholesale loads, and explain any difference in actual and projected growth rates between retail and wholesale loads, and (2) for any amount of undesignated load, detail each potential customer's current supply arrangements and explain the basis for the utility's reasonable expectation for serving each such customer.

8. That each IOU shall continue to include a discussion of a variance of 10% or more in projected EE savings from one IRP report to the next.

9. That each IOU shall continue to include a discussion of the status of EE market potential studies or updates in their future IRPs.

10. That all IOUs shall include in future IRPs a full discussion of the drivers of each class' load forecast, including new or changed demand of a particular sector or sub-group.

11. That, pursuant to the Regulatory Conditions imposed in the Merger Order, DEC and DEP shall continue to pursue least-cost integrated resource planning and file separate IRPs until otherwise required or allowed to do so by Commission order or until a combination of the utilities is approved by the Commission.

12. That DEC shall continue to provide updates in future IRPs regarding its obligations related to the Cliffside Unit 6 air permit.

13. That the Cliffside Unit 6 Carbon Neutrality Plan filed by DEC is approved as a reasonable path for DEC's compliance with the carbon emission reduction standards of the air quality permit; provided, however, this approval does not constitute Commission approval of individual specific activities or expenditures for any activities shown in the Plan.

14. That in their future IRP filings, DEP and DNCP shall provide additional details and discussion of projected alternative supply side resources similar to the information provided by DEC.

15. That in future IRPs, DEC and DEP should consider additional resource scenarios that include larger amounts of renewable energy resources similar to DNCP's Renewable Plan, and to the extent those scenarios are not selected, discuss why the scenario was not selected.

16. That, to the extent an IOU selects a preferred resource scenario based on fuel diversity, the IOU should provide additional support for its decision based on the costs and benefits of alternatives to achieve the same goals.

17. That, consistent with the Commission's May 7, 2013 Order in Docket No. M-100, Sub 135, the IOUs shall include with their 2014 IRP submittals verified testimony addressing natural gas issues, as detailed in the body of that Order.

ISSUED BY ORDER OF THE COMMISSION.

This the ______ day of October, 2013.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount, Chief Clerk

mr101413.01

Former Commissioners William T. Culpepper, III and Lucy T. Allen, and present Commissioners Don M. Bailey, Jerry C. Dockham, and James G. Patterson did not participate in this decision.

Progress Energy Carolinas

Table 1 2012 Annual IRP (Summer)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
GENERATION CHANGES															
Sited Additions	920	625													
Undesignated Additions (1)					181	370	240	787	221	787	221			185	185
Planned Project Uprates	23	9	24												
Retirements	(973)	(575)													
INSTALLED GENERATION															
Nuclear	3,540	3,549	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573	3,573
Fossil	4,095	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520	3,520
Combined Cycle	2,027	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652	2,652
Combustion Turbine	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087	3,087
Hydro	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Undesignated (1)					181	551	791	1,578	1,799	2,586	2,807	2,807	2,807	2,992	3,177
TOTAL INSTALLED	**12,974**	**13,033**	**13,057**	**13,057**	**13,238**	**13,608**	**13,848**	**14,635**	**14,856**	**15,643**	**15,864**	**15,864**	**15,864**	**16,049**	**16,234**
PURCHASES & OTHER RESOURCES															
SEPA	95	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NUG QF - Renewable	236	236	234	268	268	220	221	221	208	205	207	207	207	207	210
Butler Warner	220	220	220	220	220										
Anson CT Tolling Purchase	336	336	336	338	336	336	336	336	336	336	336	336	336	336	338
Hamlet CT Tolling Purchase	112	168	168	168	168	168									
Broad River CT	807	807	807	807	807	807	807	807	329						
Southern CC Purchase - LT	145	145	145	145	145	145	145								
TOTAL SUPPLY RESOURCES	**14,950**	**15,079**	**15,101**	**15,135**	**15,316**	**15,418**	**15,491**	**16,133**	**15,863**	**15,318**	**16,541**	**16,541**	**16,541**	**16,726**	**16,914**
PEAK DEMAND															
Retail	9,060	9,222	9,379	9,558	9,722	9,879	10,038	10,193	10,336	10,485	10,630	10,777	10,916	11,077	11,238
Wholesale	4,156	4,205	4,252	4,296	4,344	4,376	4,429	4,495	4,552	4,601	4,661	4,711	4,767	4,831	4,886
Firm (Duke Area)	150	150	150	150	150	150	150	150	150	150	150	150			
Mitigation Sale	325	325													
OBLIGATION BEFORE DSM	13,691	13,902	13,781	14,004	14,216	14,404	14,618	14,838	15,038	15,235	15,442	15,638	15,684	15,907	16,124
DSM & EE	828	881	933	985	1,031	1,073	1,116	1,162	1,208	1,253	1,297	1,338	1,375	1,409	1,441
OBLIGATION AFTER DSM	12,862	13,021	12,848	13,019	13,185	13,332	13,501	13,676	13,830	13,982	14,145	14,300	14,309	14,498	14,684
RESERVES (2)	2,087	2,058	2,253	2,116	2,131	2,086	1,990	2,457	2,033	2,336	2,396	2,241	2,232	2,228	2,230
Capacity Margin (3)	14%	14%	15%	14%	14%	14%	13%	15%	13%	14%	14%	14%	13%	13%	13%
Reserve Margin (4)	16%	16%	18%	16%	16%	16%	15%	18%	15%	17%	17%	16%	16%	15%	15%
ANNUAL SYSTEM ENERGY (GWh)	**66,066**	**66,821**	**66,575**	**67,520**	**68,333**	**69,024**	**69,867**	**70,569**	**71,234**	**71,980**	**72,729**	**73,558**	**74,172**	**75,090**	**76,025**

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.

(2) Reserves = Total Supply Resources - Firm Obligations.

(3) Capacity Margin = Reserves / Total Supply Resources * 100.

(4) Reserve Margin = Reserves / System Firm Load after DSM * 100.

Progress Energy Carolinas

Table 2 2012 Annual IRP (Winter)

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
GENERATION CHANGES															
Sited Additions	1,049	717													
Undesignated Additions (1)					147	56	476	210	875	225	875	225			210
Planned Project Uprates	78	9		28											
Retirements	(1,039)	(602)													
INSTALLED GENERATION															
Nuclear	3,668	3,677	3,677	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705	3,705
Fossil	4,170	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568	3,568
Combined Cycle	2,321	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038	3,038
Combustion Turbine	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608	3,608
Hydro	227	227	227	227	227	227	227	227	227	227	227	227	227	227	227
Undesignated (1)					147	203	679	889	1,764	1,989	2,864	3,089	3,089	3,089	3,299
TOTAL INSTALLED	**13,994**	**14,118**	**14,118**	**14,146**	**14,293**	**14,349**	**14,825**	**15,035**	**15,910**	**16,135**	**17,010**	**17,235**	**17,235**	**17,235**	**17,445**
PURCHASES & OTHER RESOURCES															
SEPA	95	95	109	109	109	109	109	109	109	109	109	109	109	109	109
NUG QF - Cogen	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NUG QF - Renewable	236	236	234	268	268	220	221	221	221	205	207	207	207	207	210
Butler Warner	260	260	260	260	260										
Anson CT Tolling Purchase	365	365	365	365	365	365	365	365	365	365	365	365	365	365	365
Hamlet CT Tolling Purchase		168	168	168	168	168	168								
Broad River CT	880	880	880	880	880	880	880	880	880	381					
Southern CC Purchase - LT	145	145	145	145	145	145	145								
TOTAL SUPPLY RESOURCES	**16,000**	**16,292**	**16,305**	**16,366**	**16,513**	**16,261**	**16,738**	**16,635**	**17,510**	**17,220**	**17,716**	**17,941**	**17,941**	**17,941**	**18,154**
OBLIGATION BEFORE DSM	12,658	12,859	13,052	13,263	13,464	13,642	13,844	14,053	14,241	14,428	14,624	14,809	14,845	15,056	15,262
DSM & EE	751	781	809	837	862	884	909	935	962	988	1,014	1,039	1,062	1,083	1,103
OBLIGATION AFTER DSM	11,907	12,078	12,242	12,426	12,602	12,758	12,935	13,118	13,279	13,440	13,609	13,770	13,783	13,973	14,159
RESERVES (2)	4,092	4,214	4,062	3,940	3,911	3,503	3,803	3,518	4,231	3,780	4,106	4,170	4,158	3,968	3,995
Capacity Margin (3)	26%	26%	25%	24%	24%	22%	23%	21%	24%	22%	23%	23%	23%	22%	22%
Reserve Margin (4)	34%	35%	33%	32%	31%	27%	29%	27%	32%	28%	30%	30%	30%	28%	28%

Footnotes:

(1) Undesignated capacity may be replaced by purchases, uprates, DSM; or a combination thereof. Joint ownership opportunities will be evaluated with baseload additions.

(2) Reserves = Total Supply Resources - Firm Obligations.

(3) Capacity Margin = Reserves / Total Supply Resources * 100.

(4) Reserve Margin = Reserves / System Firm Load after DSM * 100.

Table 8.A

Summer Projections of Load, Capacity, and Reserves for Duke Energy Carolinas 2012 Annual Plan

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Load Forecast										
1 Duke System Peak	18,105	18,554	18,975	19,486	19,947	20,386	20,830	21,155	21,552	21,921
Reductions to Load Forecast										
2 New EE Programs	(62)	(117)	(181)	(247)	(317)	(384)	(451)	(517)	(585)	(652)
3 Adjusted Duke System Peak	**18,043**	**18,437**	**18,786**	**19,238**	**19,630**	**20,002**	**20,379**	**20,638**	**20,967**	**21,268**
Cumulative System Capacity										
4 Generating Capacity	19,913	21,044	21,109	20,211	20,207	20,207	20,207	20,207	20,207	20,207
5 Capacity Additions	1,481	66	182	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	(4)	0	0	0	0	0	0
7 Capacity Retirements	(350)	0	(1,080)	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	21,044	21,109	20,211	20,207	20,207	20,207	20,207	20,207	20,207	20,207
Purchase Contracts										
9 Cumulative Purchase Contracts	340	340	328	328	328	328	261	256	170	155
Sales Contracts										
10 Catawba Owner Backstand	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0
11 Firm Sale	(150)	(150)	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions										
Base Load	0	0	0	0	0	0	0	0	0	1,117
Peaking/Intermediate	0	0	0	700	700	1,400	2,200	2,200	2,200	2,200
Renewables	38	103	171	231	256	288	374	395	426	516
13 Cumulative Production Capacity	**21,272**	**21,356**	**20,664**	**21,419**	**21,444**	**22,177**	**22,894**	**23,013**	**23,003**	**24,196**
Reserves w/o Demand-Side Management										
14 Generating Reserves	3,229	2,919	1,870	2,180	1,814	2,175	2,616	2,374	2,036	2,927
15 % Reserve Margin	**17.9%**	**15.8%**	**9.9%**	**11.3%**	**9.2%**	**10.9%**	**12.8%**	**11.5%**	**9.7%**	**13.8%**
16 % Capacity Margin	15.2%	13.7%	9.0%	10.2%	8.5%	9.8%	11.4%	10.3%	8.9%	12.1%
Demand-Side Management										
17 Cumulative DSM Capacity	872	956	1,043	1,099	1,140	1,153	1,167	1,180	1,194	1,200
IS / SG	100	95	90	88	82	82	82	82	82	82
Power Share / Power Manager	772	861	953	1,013	1,058	1,071	1,085	1,098	1,112	1,118
18 Cumulative Equivalent Capacity	**22,144**	**22,312**	**21,707**	**22,518**	**22,584**	**23,329**	**24,161**	**24,193**	**24,197**	**25,396**
Reserves w/ DSM										
19 Generating Reserves	4,101	3,875	2,912	3,279	2,954	3,328	3,783	3,554	3,230	4,127
20 % Reserve Margin	**22.7%**	**21.0%**	**15.8%**	**17.0%**	**15.0%**	**16.6%**	**18.6%**	**17.2%**	**15.4%**	**19.4%**
21 % Capacity Margin	18.5%	17.4%	13.4%	14.6%	13.1%	14.3%	15.7%	14.7%	13.3%	16.3%

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Forecast										
1 Duke System Peak	22,296	22,673	23,073	23,420	23,859	24,260	24,643	25,051	25,483	25,905
Reductions to Load Forecast										
2 New EE Programs	(720)	(785)	(854)	(921)	(988)	(1,053)	(1,123)	(1,190)	(1,257)	(1,320)
3 Adjusted Duke System Peak	**21,577**	**21,888**	**22,219**	**22,499**	**22,871**	**23,208**	**23,520**	**23,861**	**24,227**	**24,586**
Cumulative System Capacity										
4 Generating Capacity	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
5 Capacity Additions	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
Purchase Contracts										
9 Cumulative Purchase Contracts	155	155	155	155	155	155	141	141	141	141
Sales Contracts										
10 Catawba Owner Backstand	0	0	0	0	0	0	0	0	0	0
11 Firm Sale	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions										
Base Load	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	2,200	2,200	2,200	2,200	2,200	2,900	2,900	3,700	3,700	3,850
Renewables	536	567	637	661	684	701	715	729	743	758
13 Cumulative Production Capacity	**24,216**	**25,383**	**25,433**	**25,457**	**25,480**	**26,198**	**26,197**	**27,011**	**27,025**	**27,190**
Reserves w/o Demand-Side Management										
14 Generating Reserves	2,639	3,475	3,214	2,958	2,609	2,990	2,677	3,150	2,799	2,605
15 % Reserve Margin	**12.2%**	**15.9%**	**14.5%**	**13.1%**	**11.4%**	**12.9%**	**11.4%**	**13.2%**	**11.5%**	**10.6%**
16 % Capacity Margin	10.9%	13.7%	12.6%	11.6%	10.2%	11.4%	10.2%	11.7%	10.4%	9.6%
Demand-Side Management										
17 Cumulative DSM Capacity	1,207	1,207	1,207	1,207	1,207	1,207	1,207	1,207	1,207	1,207
IS / SG	82	82	82	82	82	82	82	82	82	82
Power Share / Power Manager	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125
18 Cumulative Equivalent Capacity	**25,422**	**26,570**	**26,640**	**26,664**	**26,687**	**27,405**	**27,404**	**28,218**	**28,232**	**28,397**
Reserves w/ DSM										
19 Generating Reserves	3,846	4,682	4,421	4,165	3,816	4,197	3,884	4,357	4,006	3,812
20 % Reserve Margin	**17.8%**	**21.4%**	**19.9%**	**18.5%**	**16.7%**	**18.1%**	**16.5%**	**18.3%**	**16.5%**	**15.5%**
21 % Capacity Margin	15.1%	17.6%	16.6%	15.6%	14.3%	15.3%	14.2%	15.4%	14.2%	13.4%

**Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2012 Annual Plan**

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32
Load Forecast																				
1 Duke System Peak	17,443	17,868	18,295	18,744	19,224	19,672	20,112	20,474	20,764	21,179	21,527	21,880	22,260	22,585	22,958	23,416	23,816	24,208	24,628	25,005
Reductions to Load Forecast																				
2 New EE Programs	(60)	(109)	(164)	(219)	(303)	(369)	(435)	(489)	(567)	(633)	(699)	(763)	(814)	(879)	(963)	(1,027)	(1,095)	(1,162)	(1,203)	(1,264)
3 Adjusted Duke System Peak	17,383	17,759	18,130	18,525	18,921	19,303	19,677	19,985	20,197	20,546	20,828	21,117	21,446	21,706	21,994	22,391	22,720	23,046	23,425	23,740
Cumulative System Capacity																				
4 Generating Capacity	20,318	21,766	21,801	21,867	20,969	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965
5 Capacity Additions	2,074	36	66	182	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	(4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(626)	0	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	21,766	21,801	21,867	20,969	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965
Purchase Contracts																				
9 Cumulative Purchase Contracts	347	347	335	335	335	335	288	265	170	155	155	155	155	155	155	155	141	141	141	141
Sales Contracts																				
10 Catawba Owner Backstand	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0	0
11 Firm Sale	(25)	(25)	(25)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	700	700	1,400	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,900	2,900	3,700	3,700
Renewables	16	38	103	171	231	256	288	374	395	426	516	536	567	637	661	684	701	715	729	743
13 Cumulative Production Capacity	22,103	22,116	22,233	21,429	22,184	22,209	22,873	23,766	23,729	23,746	24,953	24,973	26,121	26,191	26,216	26,238	26,941	26,965	27,769	27,783
Reserves w/o Demand-Side Management																				
14 Generating Reserves	4,720	4,356	4,103	2,903	3,263	2,906	3,197	3,771	3,532	3,200	4,125	3,856	4,675	4,485	4,220	3,847	4,221	3,907	4,344	4,043
15 % Reserve Margin	27.2%	24.5%	22.6%	15.7%	17.2%	15.1%	16.2%	18.9%	17.5%	15.6%	19.8%	18.3%	21.8%	20.7%	19.2%	17.2%	18.6%	17.0%	18.6%	17.0%
16 % Capacity Margin	21.4%	19.7%	18.5%	13.5%	14.7%	13.1%	14.0%	15.9%	14.9%	13.5%	16.5%	15.4%	17.9%	17.1%	16.1%	14.7%	15.7%	14.5%	15.6%	14.6%
Demand-Side Management																				
17 Cumulative DSM Capacity	570	595	617	635	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653
IS / SG	100	95	90	86	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
Power Share / Power Manager	470	500	527	549	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
18 Cumulative Equivalent Capacity	22,673	22,710	22,850	22,063	22,837	22,862	23,526	24,409	24,382	24,399	25,606	25,626	26,774	26,844	26,868	26,891	27,594	27,608	28,422	28,436
Reserves w/ DSM																				
19 Generating Reserves	5,290	4,951	4,719	3,537	3,916	3,559	3,849	4,424	4,185	3,853	4,777	4,509	5,328	5,138	4,873	4,499	4,874	4,560	4,997	4,896
20 % Reserve Margin	30.4%	27.9%	26.0%	19.1%	20.7%	18.4%	19.6%	22.1%	20.7%	18.6%	22.9%	21.3%	24.8%	23.7%	22.2%	20.1%	21.6%	19.8%	21.3%	19.8%
21 % Capacity Margin	23.3%	21.8%	20.7%	16.0%	17.1%	15.6%	16.4%	18.1%	17.2%	15.8%	18.7%	17.6%	19.9%	19.1%	18.1%	16.7%	17.7%	16.5%	17.6%	16.5%

Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer and Winter Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

5. Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Dan River Combined Cycle facility).
Capacity Additions include the conversion of Lee Steam Station unit 3 from coal to natural gas in 2015 (170 MW).
Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2012-2015 timeframe and total 2 MW.
Also included is a 111 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2015

6. Capacity Derate of 4 MW associated with Marshall 4 SCR is included in 2016

7. The 350 MW capacity retirement in summer 2013 represents the projected fall 2012 retirement date for the old fleet CT retirements
The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
All retirement dates are subject to review on an ongoing basis.

9. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects totaling 132 MW in 2013.

10-11. A firm wholesale backstand agreement up to 277 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020. Firm sale of 150 MW summer and 25 MW winter for FERC market power mitigation.

12. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand
Occurences when Reserve Margin exceeds +/-3% of the 15.5% target planning reserve margin:2013-2014 Reserve Margin
   1) 2013-2014: Due to the addition of Buck and Dan River CC and Cliffside 6 PC units coupled with lower economic load growth.
   2) 2019: Due to the addition of 800 MW of CT capacity to meet resource need in 2019, 2020 and 2021.
   3) 2022, 2024, and 2025: Due to the addition of 1117 MW nuclear units to meet long-term resource need in 2022 and 2024.

16. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

APPENDIX 2H – PROJECTED SUMMER & WINTER PEAK LOAD & ENERGY FORECAST

Company Name: Virginia Electric and Power Company — **Schedule 1**

I. PEAK LOAD AND ENERGY FORECAST

	(ACTUAL)(1)			(PROJECTED)															
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1. Utility Peak Load (MW)																			
A. Summer																			
1a. Base Forecast	15,917	16,783	17,521	16,711	17,039	17,424	17,883	18,254	18,580	18,896	19,230	19,532	19,909	20,247	20,579	20,897	21,182	21,502	21,847
1b. Additional Forecast																			
NCEMC	150	150	150	150	150	150	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency(5)	-	-17	-10	-46	-47	-53	-94	-192	-261	-297	-297	-295	-293	-296	-298	-301	-303	-304	-307
3. Demand Response(2)(5)	-	-21	-29	-65	-119	-200	-253	-306	-354	-383	-411	-437	-463	-489	-495	-502	-506	-510	-515
4. Demand Response-Existing(2)(3)	-18	-9	-7	-7	-7	-7	-7	-7	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Peak Adjustment	-	-	-	319	407	556	805	-	-	-	-	-	-	-	-	-	-	-	-
6. Adjusted Load	16,067	16,933	17,661	17,134	17,550	18,077	18,595	18,062	18,318	18,599	18,933	19,238	19,617	19,951	20,280	20,596	20,879	21,198	21,540
7. % Increase in Adjusted Load (from previous year)	-5.0%	5.4%	4.3%	-3.0%	2.4%	3.0%	2.9%	-2.9%	1.4%	1.5%	1.8%	1.6%	2.0%	1.7%	1.6%	1.6%	1.4%	1.5%	1.6%
B. Winter																			
1a. Base Forecast	15,427	15,184	15,252	14,544	15,093	15,267	15,611	16,173	16,432	16,672	16,813	17,020	17,411	17,663	17,924	18,160	18,291	18,666	18,934
1b. Additional Forecast																			
NCEMC	150	150	150	145	146	147	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Conservation, Efficiency(5)	-	-14	13	-29	-30	-35	-73	-158	-203	-225	-224	-222	-219	-222	-224	-226	-228	-229	-230
3. Demand Response(2)(4)	-	-12	-	-	-18	-45	-48	-56	-64	-71	-76	-79	-82	-86	-89	-92	-93	-94	-94
4. Demand Response-Existing(2)(3)	-21	-7	-6	-6	-8	-6	-6	-6	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5	-5
5. Adjusted Load	15,577	15,334	15,402	14,659	15,209	15,379	15,738	16,014	16,228	16,446	16,588	16,798	17,191	17,442	17,700	17,934	18,063	18,438	18,704
6. % Increase in Adjusted Load	5.3%	-1.6%	0.4%	-4.8%	3.7%	1.1%	2.3%	1.8%	1.3%	1.3%	0.9%	1.3%	2.3%	1.5%	1.5%	1.3%	0.7%	2.1%	1.4%
2. Energy (GWh)																			
A. Base Forecast	82,501	86,663	83,393	85,531	87,283	89,650	92,153	94,179	95,535	97,161	98,883	100,905	102,455	104,260	106,042	108,115	109,635	111,388	112,996
B. Additional Forecast																			
NCEMC	-	-	-	645	658	676	-	-	-	-	-	-	-	-	-	-	-	-	-
ODECsupp(4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
C. Conservation & Demand Response(5)	-	-	-	-470	-526	-707	-1,098	-1,610	-2,189	-2,642	-2,974	-3,202	-3,338	-3,350	-3,383	-3,372	-3,382	-3,389	-3,400
D. Demand Response-Existing(2)(3)	-2	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
E. Adjusted Energy	82,501	86,663	83,393	85,706	87,415	89,618	91,057	92,568	93,346	94,519	95,909	97,703	99,117	100,911	102,679	104,743	106,254	107,999	109,597
F. % Increase in Adjusted Energy	-1.3%	5.0%	-3.8%	2.8%	2.0%	2.5%	1.6%	1.7%	0.8%	1.3%	1.5%	1.9%	1.4%	1.8%	1.8%	2.0%	1.4%	1.6%	1.5%

(1) Actual metered data.

(2) Demand response programs are classified as capacity resources and are not included in adjusted load.

(3) Existing DSM programs are included in the load forecast.

(4) ODEC contract expired year end 2010

(5) Values reflect firm capacity

APPENDIX 2I – REQUIRED RESERVE MARGIN

Company Name: Virginia Electric and Power Company

Schedule 6

POWER SUPPLY DATA (continued)

	(ACTUAL)			(PROJECTED)															
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
I. Reserve Margin[1]																			
(Including Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	1,964	3,397	3,240	2,991	3,513	3,205	2,804	1,987	2,015	2,046	2,135	2,116	2,158	2,195	2,231	2,390	2,311	2,332	2,370
b. Percent of Load	12.2%	20.1%	18.3%	17.5%	20.0%	17.7%	15.1%	11.0%	11.0%	11.0%	11.3%	11.0%	11.0%	11.0%	11.0%	11.6%	11.1%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	14.45%	12.53%	9.30%	5.75%	16.43%	11.04%	9.29%	13.90%	12.02%	12.01%	11.26%	9.56%	15.01%	13.48%	11.80%	10.05%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	4,985	4,520	4,338	4,449	4,967	4,696	3,600	4,919	4,496	4,534	4,574	4,363	5,665	5,533	5,157	4,887
b. Percent of Load	N/A	N/A	N/A	33.9%	29.7%	28.1%	28.2%	30.8%	28.6%	21.9%	29.8%	26.9%	26.5%	26.3%	24.7%	31.7%	30.7%	28.0%	26.2%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
I. Reserve Margin[1][2][3]																			
(Excluding Cold Reserve Capability)																			
1. Summer Reserve Margin																			
a. MW[1]	1,964	3,323	3,135	2,917	3,439	3,131	2,804	1,987	2,015	2,046	2,135	2,116	2,158	2,195	2,231	2,390	2,311	2,332	2,370
b. Percent of Load	12.2%	19.6%	17.8%	17.0%	19.6%	17.3%	15.1%	11.0%	11.0%	11.0%	11.3%	11.0%	11.0%	11.0%	11.0%	11.6%	11.1%	11.0%	11.0%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	13.59%	11.69%	8.48%	5.75%	16.43%	11.04%	9.29%	13.90%	12.02%	12.01%	11.26%	9.56%	15.01%	13.48%	11.80%	10.05%
2. Winter Reserve Margin																			
a. MW[1]	N/A	N/A	N/A	4,908	4,443	4,261	4,449	4,967	4,696	3,600	4,919	4,496	4,534	4,574	4,363	5,665	5,533	5,157	4,887
b. Percent of Load	N/A	N/A	N/A	33.4%	29.2%	27.6%	28.2%	30.6%	28.6%	21.9%	29.8%	26.9%	26.5%	26.3%	24.7%	31.7%	30.7%	28.0%	26.2%
c. Actual Reserve Margin[4]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
III. Annual Loss-of-Load Hours[5]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(1) To be calculated based on Total Net Capability for summer and winter.
(2) The Company has one unit in cold reserve.
(3) The Company and PJM forecasts a summer peak throughout the Planning Period.
(4) Does not include purchases of capacity.
(5) The Company follows PJM reserve requirements which are based on LOLE.

North Carolina Electric IOU Service Area Map